

**OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY  
AIR QUALITY DIVISION**

**MEMORANDUM**

**November 21, 2014**

**TO:** Phillip Fielder, Permits and Engineering Group Manager

**THROUGH:** Kendal Stegmann, Sr. Environmental Manager, Compliance and Enforcement

**THROUGH:** Phil Martin, P.E., Existing Source Permits Section Manager

**THROUGH:** Peer Review, David Pollard, DEQ Regional Office at Tulsa (ROAT)

**FROM:** Herb Neumann, DEQ ROAT

**SUBJECT:** Evaluation of Permit Application No. **98-171-C (M-2) PSD**  
Cabot Norit Americas, Inc.  
Pryor Activated Carbon Plant (SIC 2819)  
SW/4 SE/4 Sec. 4, T20N, R19E, Mayes County (36.238° N, 95.286° W)

Driving: From intersection of US 412 and US 69, six miles north to US 69A, three miles east to US 412B (Hunt Street), one mile south to 6<sup>th</sup> Street, almost ½ mile west, plant on left. Alternately, from US 412 and US 69, three miles east to US 412B (becomes Hunt), almost five miles north to 6<sup>th</sup> Street, same as above.

**SECTION I. INTRODUCTION**

Cabot Norit Americas (Cabot) owns and operates a virgin activated carbon or VAC (original straight run and acid washed carbon) manufacturing plant and a spent activated carbon (SAC) regeneration facility at its Pryor, Oklahoma facility. The facility was originally constructed in 1979 as authorized by Permit No. 78-002-C. A table listing each permit and its issue date is available in the Memorandum associated with Part 70 operating permit No. 98-171-TV, issued October 11, 2010. The facility currently operates under permit No. 98-171-TV (M-8), issued January 14, 2014. Numerous additions and changes in operation of the facility have been authorized over the years. At issue in this application is the construction of the Primary Carbonizer and ancillary equipment authorized by Permit No. 88-105-C. Information supplied in the application for that permit indicated that no pollutant would have emissions of more than 250 TPY on a facility-wide basis after completion of the project. Although EPA has determined that the major stationary source threshold for this type of facility is 100 TPY, DEQ believed (in 1988) that the threshold was 250 TPY, so that the facility did not require Prevention of Significant Deterioration (PSD) applicability analysis. A subsequent material balance performed by the facility indicated that the Primary Carbonizer project exceeded the 250 TPY threshold by itself and should have been subject to PSD analysis, regardless of the actual threshold. Further, any such analysis should have included all potential upstream and downstream effects of the project. A Consent Order (CO) dated August 6, 2007, requires that a retroactive PSD analysis be performed for the project. The analysis shall cover the Primary and Secondary Carbonizers and

both activator furnaces. The current application contains the required analysis and discusses the construction of various control equipment, as described in the following paragraph.

Consent Order 07-010, issued August 6, 2007, required that a revised Title V application be provided and that a retroactive PSD analysis be prepared for the Primary Carbonizer project. The revised Title V application was received December 4, 2007 and the operating permit has been issued, as stated above. An application covering the PSD analysis was received on the same date, and is the subject of this permit. The Order also required that additional control be added to the activation furnaces, which has been accomplished by adding cyclones following each activation furnace and before the afterburner for each. Finally, the Order required the installation of additional PM control on the Secondary Carbonizer. This was accomplished by adding a bank of mini-cyclones in the exhaust stream after the afterburner and waste heat boiler.

This retroactive PSD permit has been delayed for various reasons, including the promulgation of new SO<sub>2</sub> and NO<sub>x</sub> National Ambient Air Quality Standards (NAAQS) and PSD increments. The current Part 70 permit includes a compliance plan concerning the remaining issues, and this construction permit is designed to satisfy certain requirements of that plan. Equipment and emission points shown in this Memorandum and authorized in the permit are similar to those in the existing Part 70 operating permit.

## SECTION II FACILITY DESCRIPTION

Process descriptions for the base operating scenarios for the VAC and SAC plants follow. No alternative operating scenarios are required to define operations at the facility. Commercial-grade natural gas is the primary fuel, with the facility being operated continuously. The following descriptions appear in the Memorandum for 98-171-TV (M-8), but the only portion of concern in this permit effort is Area 30.

### Virgin Plant Operation

- Receiving bituminous coal, subbituminous coal, and coal tar pitch by truck and rail from various sources; unloading and storing the coal and pitch.
- Drying the coal, blending with coal tar pitch, milling and compacting the coal/pitch material into uniform briquettes, and grinding the briquettes to the desired granule size.
- Processing the granulated briquettes through carbonizers (kilns), using natural gas as the primary fuel source for carbonization, to drive off the volatile matter and produce carbonized granules. Using heat from natural gas combustion in the activator furnaces together with steam to activate the carbon; that is, to create a porous structure in the carbon.
- Additional milling to create powdered products. Handling, storing and loading of the activated carbon into bags or trucks for final shipment to customers.
- Using dilute hydrochloric acid (HCl) to remove, through a wash or leach operation, acid-soluble constituents from part of the activated carbon produced by the virgin plant.

The virgin plant utilizes the following five basic operating areas.

- Area 10 - Material Handling Operations
- Area 20 - Material Drying, Milling, Compacting and Sizing Operations
- Area 30 - Carbonizing and Activation Operations
- Area 40 - Finished Product Packaging Operations
- Acid Wash Plant Operations

### **Area 10 - Material Handling Operations**

Coal arrives at the plant via rail or truck and is unloaded in the raw material unloading building or at the coal unloading pile, and is moved within the unloading building, eventually to the working coal storage pile. Front-end loaders are used to transfer the coal into either the open coal storage area or into the dry coal storage building, as well as to maintain the coal piles in both areas. They also transfer coal from the piles to the coal hoppers at the beginning of Area 20 operations. The only particulate matter (PM) emission controls for the storage buildings and chutes are enclosures, some partial and others complete.

Coal is “reclaimed” from the coal storage and processing areas by a front-end loader that transports the reclaimed coal and maintains the reclaim coal pile. Front-end loaders transfer the coal to the reclaim coal hopper and transfer reclaimed coal to Area 20 operations.

Coal tar pitch, which is used in Area 20 as a coal binding agent, arrives at the plant via rail or bulk bags. The pitch received by rail is unloaded in the raw material unloading building, where it is transferred into piles within the pitch storage building. During rail offloading, negative pressure is maintained in the pitch storage building and any emissions are captured, reduced by the pitch storage building high efficiency panel filter, and vented through the pitch building exhaust stack. The pitch storage building is normally closed, except during periods of pitch maintenance/reclaim by front-end loader and while dropping pitch into the pitch hopper. Bulk bags are normally received in iso containers and are stored in the pitch building, in the SAC warehouse, or emptied onto the pitch building storage pile. Pitch is transferred to Area 20 via a front end loader and dumped into the pitch receiving hopper. The pitch hopper is enclosed, maintained under negative pressure, and controlled by the Area 20 dust collector.

### **Area 20 - Material Sizing and Drying Operations**

The purpose of Area 20 is to form the raw coal and pitch materials into a homogeneous material of uniform size and hardness, as required for activated carbon processing in Area 30. Phosphoric acid is added to incoming subbituminous coal as a processing aid. The process chemistry is such that there are no phosphoric acid emissions from this process. A purged air and steam coal dryer removes moisture from the coal. After the coal is dried, it is then pulverized and ground with the pitch and compacted into granular briquettes of uniform hardness. The briquettes are milled to the desired granule size. The granular material is dropped into a surge bin to control the transfer rate to Area 30 operations. The coal drying operation, Area 20, is subject to NSPS Subpart Y – Coal Preparation Plants. The coal dryer dust collector controls PM emissions from the coal

dryer. The Area 20 dust collector controls PM emissions from other coal handling operations in Area 20.

### **Area 30 - Carbonizing and Activation Operations**

The primary processes within Area 30 are two kilns, designated as the Primary and Secondary Carbonizers, and two multiple-hearth furnaces, designated as the activator furnaces. The Primary and Secondary Carbonizers are slowly rotating cylinders in which heat is applied to the granular material to drive off water and volatile organic compounds (VOCs) and to reduce the material to elemental carbon (thus “carbonizing” it). Heat is supplied indirectly by gas-fired burners installed in heating jackets positioned on the outside of each rotating cylinder. Heat is transferred to the granular material by conduction and radiation. As the granular material flows from the feed end to the discharge end of the kiln, a counter-current flow of heated air, fed to the discharge end, purges the water vapor, VOCs, and coal fines from the material and begins the process of forming a pore structure in the elemental carbon.

The granules produced in Area 20 are fed to the Primary Carbonizer. The Primary Carbonizer feed bag house controls emissions from the raw material feed system. The Primary Carbonizer is the initial step in driving off the volatile matter. It operates at a lower temperature range than the Secondary Carbonizer. This process continues at higher temperatures in the Secondary Carbonizer. Heated air with reduced oxygen is used in the Secondary Carbonizer to minimize oxidation of the carbon. The process off-gases contain particulate matter and volatile matter. Organic compounds are controlled by thermal oxidation in afterburners; each Carbonizer is equipped with its own afterburner. Waste heat boilers follow each afterburner. The Secondary Carbonizer has a multiclone particulate separator for PM control after the exhaust stream exits the waste heat boiler.

The carbonized granules are then fed to the east and west activator furnaces for further processing. These are two multiple hearth furnaces that operate in parallel. In the activator furnaces, heat is again applied to the carbonized granules, first by contacting it with hot process gases and then by contacting it with steam, to drive off any remaining volatile compounds and to complete the formation of the pore structure of the product so that the carbon granules are “activated” for their intended end use. Each activator furnace consists of a refractory-lined cylindrical steel shield containing a series of horizontal refractory hearths. The upper hearths are used to heat the carbon and drive off any remaining volatile compounds. The remaining hearths are used for the actual activation of carbon. These hearths have alternate in-feed and out-feed directions, causing carbon granules to move completely across each hearth as they drop from one level to another. The vertical orientation of the hearths have the effect of creating a counter-current flow of carbon granules moving downward and hot process gases and steam moving upward. Mechanical stoking is provided by a motor-driven revolving center shaft to which radial arms are attached. These arms have teeth (or plows) attached that move the material across the hearth to the peripheral or central openings, called drop holes, through which the granules drop to the next hearth. Multiple gas-fired burners provide auxiliary heat. Steam and process air is introduced selectively at various hearths from levels 2 through 12 to control and enhance the activation process. The process off-gases contain products of natural gas combustion, particulate matter, and some remaining volatile compounds. The off-gas from each activator furnace passes

through a cyclone for the removal of particulate matter. PM recovered by these units is generally salable material and is returned to the activation furnace. Off-gas leaving each cyclone then enters an afterburner for each unit to oxidize any remaining organic matter. Exhaust gases from the afterburners may be emitted to the atmosphere directly or passed through a waste heat boiler first.

#### **Area 40 - Finished Product Packaging Operations**

Activated carbon from Area 30 is then screened, packaged, and/or milled into powdered activated carbon (PAC) as necessary in Area 40. Activated carbon granules are transferred from the activation furnaces and dropped into the Area 40 product screener. Emissions are controlled by the Area 40 Auxiliary Dust Collector. Depending on customer requirements, the activated carbon granules and fines can be sent to the powdered activated carbon (PAC) mill for milling or to the packaging area. The PAC mill dust collector controls PAC mill emissions and the Area 40 dust collector controls packaging emission.

#### **Acid Wash Plant Operations**

The acid wash plant (AWP) is an auxiliary process to the virgin activated carbon manufacturing plant. The AWP uses dilute hydrochloric acid (HCl) to remove, through a wash or leach operation, acid soluble constituents from activated carbon produced by the virgin plant. This auxiliary process allows the production of a higher quality activated carbon that is required by certain industrial processes, such as food processing or pharmaceuticals.

The activated carbon granules from the activation furnaces are transferred from Area 40 and dropped into the acid wash reactor in batches. The activated carbon is processed through a relatively high temperature, medium pressure reaction with dilute HCl. The batch is then water washed in several steps. A buffering/neutralizing agent may be used as a rinsing agent to adjust the quality of the plant water supply. Following the water washing, the batch is then de-watered. A natural gas-fired acid-wash dryer is used to reduce the moisture content. The final product is sized and packaged.

Emissions from the HCl storage tank pass through a caustic scrubber. PM emissions arising from the transfer of granules to the acid wash reactor are controlled by the Area 20 dust collector. PM emissions from the acid wash dryer, product screener and product bin are controlled by the AWP dust collector and vented through its stack.

#### **Regeneration Plant Operation**

Spent activated carbon (used activated carbon that has adsorbed chemical constituents) is typically brought to the regeneration plant via bulk tank trucks and containers. Bulk tank trucks are pressurized to drive the spent activated carbon (SAC) into storage silos, where it is conveyed into a feed silo, and then into the regeneration kiln. Alternatively, bulk trucks are offloaded onto the SAC storage pad, which is a contained, outdoor unit. SAC received in containers is received and stored/staged in a warehouse or stored outside. Bulk SAC is transferred from the SAC pad to the Regen kiln feed hopper (F hopper). Containerized SAC is transferred from the warehouse and manually poured into the F hopper or poured onto the SAC pad. The regeneration kiln drives the adsorbed chemical constituents from the spent carbon. After regeneration, the

reactivated carbon is cooled in a non-contact water-cooled heat exchanger, then screened and packaged or bulk loaded into trucks.

Emission controls in the regeneration process include an afterburner, a baghouse, and an alkaline scrubber (for HCl and SO<sub>x</sub> removal). When the afterburner is not in service, the silos vent any VOC emissions through a carbon canister. The Regeneration Product Area Dust Collector controls packaging emissions. Truck loading operations use only a chute to control emissions.

### SECTION III. EQUIPMENT

Emission units (EUs) have been arranged into Emission Unit Groups (EUGs) in Section III (Equipment), based on activity, type of control, and permitting status. All EUGs are listed, but only those in Area 30 are described.

#### EUG 1 Facility-wide

#### EUG 2 Primary Carbonizer/Afterburner

EU	Point ID	Name/Model	Const. Date
17	SV-VP-005	Primary Carbonizer/ Afterburner/Waste Heat Boiler	1990

The PC afterburner has three burners with 12 MMBTUH total heat input.

#### EUG 3 Secondary Carbonizer/Afterburner

EU	Point ID	Name/Model	Const. Date
12	SV-VP-007a,b	Sec. Carb./Multiclone/Afterburn/ Waste Heat Boiler	1979*

\*Multiclones were installed and became operational 10/9/2006.

Oxygen content of sweep air supplied to the SC is depleted by a 14.6 MMBTUH burner. The SC afterburner has two burners with 1.9 MMBTUH total heat input. The (a) stack is designated for the direct discharge of the afterburner and the (b) stack is designated for the discharge of the waste heat boiler. The afterburner also has supplemental gas feed used as necessary. Combined maximum potential heat input is estimated at 18 MMBTUH.

#### EUG 4 Primary Carbonizer Heating Jacket

EU	Point ID	Name/Model	Const. Date
21	SV-VP-006	Primary Carbonizer Heating Jacket	1990

The Primary Carbonizer (PC) heating jacket has eight burners with total heat input of 8 MMBTUH.

#### EUG 5 Secondary Carbonizer Heating Jacket

EU	Point ID	Name/Model	Const. Date
22	SV VP 008	Secondary Carbonizer heating jacket	1979

The Secondary Carbonizer (SC) heating jacket has 8 burners with 10MMBTUH total heat input.

#### EUG 6 Activator Furnaces

The East and West activator furnaces each have 20 small burners with a combined total heat input of 25 MMBTUH, and each has a single 2.2 MMBTUH burner in its respective afterburner.

EU	Point ID	Name/Model	Const. Date
10	SV-VP-009a, b	East Activator Furnace	1979
11	SV-VP-010a, b	West Activator Furnace	1979

Exhausts from each activator furnace flow through a cyclone for PM removal/recovery and to an afterburner for destruction of organic material. A portion of both gas streams vent through a common waste heat boiler (a) or are discharged directly to the atmosphere (b).

**EUG 7 Acid Wash Dryer**

**EUG 8 Material Handling & Transfer – Controlled**

**EUG 9 Coal Processing Plant (Area 20)**

**EUG 10 Material Handling, Transfer, Traffic, & Erosion – Uncontrolled**

**EUG 11 Acid Wash Plant Material Handling & Transfer – Controlled**

**EUG 12 Material Handling & Transfer – Controlled**

**EUG 13 Material Handling, Transfer, Traffic, & Erosion – Uncontrolled**

**EUG 14 Truck Unloading**

**EUG 15 Regeneration Kiln/Afterburner**

**EUG 16 Regeneration Plant Material Handling**

**EUG17 Regeneration Plant Bulk Handling**

**EUG18 Hydrochloric Acid Storage Tank**

**EUG 19 NSPS Subpart Dc Boiler (Permit No. 98-171-C (M-1))**

**EUG 20 Cooling Tower**

**EUG 21 NSPS Subpart III Engine**

### **SECTION III. EMISSIONS**

Calculating emissions from the Carbonizers and activator furnaces is difficult. Analyses from previous permit memoranda, including the current Part 70 permit, are set aside, and only the methods proposed in the application are used. As a condition of the Consent Order, a PSD applicability analysis was required and submitted. In this analysis, emissions from each affected unit were estimated through a material balance calculation. PM emissions from the VAC can be

assessed by considering the amount of dry material feed and the amount of dry material product. This can be refined by reviewing the amount of dry feed at each of the processing units; that is, at the Primary Carbonizer, the Secondary Carbonizer, and at the activator furnaces, allowing a calculation of what portion of total emissions is attributable to each process component. Further considerations address ash content of the raw material and review both the genesis and the fate of both ash and non-ash PM. For the purposes of modeling, cyclones are assumed to be 80% efficient and afterburners 90% efficient, noting that afterburners affect only the non-ash PM. This methodology involves confidential data, so no further discussion is offered here, but the method is addressed in the Specific Conditions of Permit No. 98-171-TV. For the purpose of reporting PM emissions using the model described above, all values of PM are assumed to be PM<sub>10</sub>. Pre-project emissions average 984 TPY over the 1986/87 base years, using the methodology described above. Post-project emissions total 602 TPY, but note that the decrease is largely due to the yield improvements achieved by the project and the installation of cyclones at the Secondary Carbonizer in 2006 and at the activator furnaces in 2008. Annual post-project values are based on 8,760 hours of operation. Norit conducted particulate matter stack tests on major stacks at the Pryor Facility in May 2009. The stack tests contained 11 cumulative particle size analysis profiles for two emission sources. The cumulative PM<sub>2.5</sub> volume percent ranged from 0.82% to 14.02% of all PM<sub>10</sub>. The weight percent numerically equal to the highest volume percent measured during the tests (14.02%) is used to represent the ratio of PM<sub>2.5</sub> to PM<sub>10</sub> as a conservative estimate.

Post-project emissions of NO<sub>x</sub> are calculated based upon 2004 stack testing results. There is no reason to assume linearity; that is, emissions of this pollutant will probably not increase linearly with increased production, because thermodynamic considerations are not predictable. The facility's consultant suggested that the emissions be treated as varying directly with the square of the production rate. Because these calculations reveal proprietary process information, only the results (701.3 TPY) are given.

Post-project emissions of CO are calculated in the same manner as those of NO<sub>x</sub>, yielding 53.1 TPY.

Pre- and post-project emissions of VOC have been calculated based on May and June 1997 tests of each unit, and assuming linearity. The factors evolved from those tests are 0.015 lb/ton for the primary, 0.073 lb/ton for the secondary, 0.060 lb/ton for the east activator furnace, and 0.070 lb/ton for the west activator furnace. The 1986/87 average dry feed rate was 39,910 TPY, yielding 4.05 TPY of VOC emissions. Using the maximum feed rate of 78,840 TPY for post-project calculations yields 8.6 TPY, to which 10 activator furnace startup events at 1,954 pounds each are added, for a total of 18.4 TPY of VOC emissions.

Total pre-project emissions of SO<sub>2</sub> from the VAC were estimated based on material balance for the entire process. The sulfur content of the raw material (feed) is known or measurable, as is the sulfur content of the product. The amounts of feed and of resulting product are also known factors. The loss in sulfur between inlet and outlet may be calculated from these known data, and by assuming that all of this sulfur is stoichiometrically oxidized to sulfur dioxide, the estimated baseline actual emissions for the 1986 – 1987 period was estimated at 370.3 TPY of SO<sub>2</sub>. As discussed in the BACT analysis, sulfur input to the process will be limited to 150 lb/hr.



Maximum potential SO<sub>2</sub> emissions rates were estimated by Cabot based on the proposed maximum sulfur input rate of 150 lb/hr in combination with assumptions (based on operating experience) about production yield, product sulfur content, and 100% conversion of all feed sulfur that is not contained in the product to SO<sub>2</sub> emissions. Based on the estimates submitted in the permit application, the maximum allowable SO<sub>2</sub> emissions from the VAC process will be 211 lb/hr or 924 TPY.

Fluoride emissions were calculated using factors evolved from testing performed in May and June, 1997. Factors are 0.009 lb/ton for the primary, 0.002 lb/ton for the secondary, and 0.037 lb/ton for each activator furnace, where the West activator furnace was tested and the East activator furnace was assumed to be identical. Pre-project emissions total 1.50 TPY and post-project emissions total 3.32 TPY.

A small amount of associated emissions need to be recognized, all of which are PM occasioned by greater throughput in Areas 10, 20, and 40. Area 10 includes activities such as raw material offloading, pitch building, wind erosion, and traffic. Area 20 is coal preparation, and Area 30 is product handling. Each of these three areas has numerous small sources within it, but all three have emissions calculations in direct proportion to material throughput. Therefore, the ratio of 39,910 tons of feed handled in the baseline years to the conservatively high assumption of 9 TPH is used to calculate PTE, and therefore, the emission increase for these areas. The following figures are added to those for Area 30 in the PSD analysis appearing later in this memorandum. All PM is assumed to be PM<sub>10</sub>, and arbitrarily treated as PM<sub>2.5</sub> in the subsequent PSD analysis.

	Material handled	PM Emissions (TPY)			
	TPY	Area 10	Area 20	Area 40	Total
1986/87	39,910	19.22	0.73	0.14	20.1
PTE (9 TPH)	78,840	37.97	1.44	0.28	39.7
Increase	N/A	18.75	0.71	0.14	19.6

#### SECTION IV. INSIGNIFICANT ACTIVITIES

None of the insignificant activities identified in the Part 70 permit application is affected by this project, so the list is not duplicated here. It is available in the Memorandum associated with Permit No. 98-171-TV (M-8).

#### SECTION V. PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

Physical changes at the facility involve adjusting various stacks. Combustion gas flows for the Primary Carbonizer waste heat boiler stack, the Secondary Carbonizer waste heat boiler stack, and the Secondary Carbonizer afterburner stack will be combined into a new stack to be located south of the Primary Carbonizer. These gases will vent to atmosphere through the 6' diameter new stack at 120' above grade. The Primary Carbonizer waste heat boiler stack will be eliminated, and the other two stacks will be ducted to the new stack with the addition of an induced draft fan. An air quench system will be installed between the afterburner exhaust and the induced draft fan. The existing activator furnace waste heat boiler stack will be eliminated, and emissions from the waste heat boiler will be ducted into the existing activator furnace main

stack, which will be adjusted to a 6' diameter, and exhaust at 140' above grade. These data are embedded in the various modeling scenarios discussed later in this section.

Calculation of pre- and post-project emissions was discussed in Section III above. Note that the bases for the pre-project calculations varied among pollutants. The table of emissions increases/decreases follows.

**Table 1**

Pollutant	Emission Type	Emissions (TPY)	PSD Threshold	Significant?
PM	Pre	984.0		
	Post	621.8		
	Change	-362.2	25	No
PM <sub>10</sub>	Pre	984.0		
	Post	621.8		
	Change	-362.2	15	No
PM <sub>2.5</sub>	Pre	137.8		
	Post	103.9		
	Change	-33.9	10	No
PM <sub>2.5</sub> (As NO <sub>x</sub> )	Pre	172.6		
	Post	706.9		
	Change	534.3	40	Yes
PM <sub>2.5</sub> (As SO <sub>2</sub> )	Pre	370.3		
	Post	929.3		
	Change	559.0	40	Yes
SO <sub>2</sub>	Pre	370.3		
	Post	923.7		
	Change	553.4	40	Yes
NO <sub>x</sub>	Pre	172.6		
	Post	701.3		
	Change	528.7	40	Yes
CO	Pre	6.2		
	Post	53.1		
	Change	46.9	100	No
VOC	Pre	4.05		
	Post	18.4		
	Change	14.3	40	No
Lead	Pre	0.30		
	Post	0.59		
	Change	0.29	0.6	No
Fluorides	Pre	1.51		
	Post	3.32		
	Change	1.81	3	No

As indicated in this table, the Primary Carbonizer Project is subject to full PSD review for SO<sub>2</sub> and NO<sub>x</sub>. BACT requirements apply to SO<sub>2</sub> and NO<sub>x</sub>. BACT does not apply to PM<sub>2.5</sub> because direct emissions of PM<sub>2.5</sub> did not increase as a result of the project. However, because SO<sub>2</sub> and NO<sub>x</sub> are PM<sub>2.5</sub> precursors, BACT must be demonstrated for them as such. In this instance the

BACT demonstration for SO<sub>2</sub> and for NO<sub>x</sub> is sufficient to demonstrate BACT for each of them as precursors.

A BACT Review is required for new and modified emission units that result in a PSD net emission increase. Title 40 CFR 52.21(j)(3) codifies the BACT requirement as follows: “A major modification shall apply best available control technology for each pollutant subject to regulation under the Act for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or a change in the method of operation.”

The scope of the 1988 project at the Pryor Facility was the installation of a new carbonizer, called the Primary Carbonizer because it was installed upstream of the existing (now secondary) carbonizer. The purpose of the project was to increase VAC production capacity and allow the use of varying types of coal as VAC process feedstock. The historical project descriptions indicated that the physical changes associated with the project included the addition of the Primary Carbonizer and associated material handling systems. As previously presented in Section 2, the output from the Primary Carbonizer is directed to the Secondary Carbonizer. Therefore, the feed conveyance system to the Secondary Carbonizer may be considered to have been modified as a result of this 1988 project, arguably resulting in a modification to the Secondary Carbonizer. No other physical changes were made to equipment within the VAC process. Additionally, it is not believed that there was a change in the method of operation for any downstream process after the Secondary Carbonizer (i.e., the activator furnaces). This is due to the fact that EPA does not consider a change in feedstock a change in the method of operation if the emission unit was always capable of processing the feedstock. It is apparent that the activator furnaces could always have processed the “new” feedstock to the extent that it was properly carbonized since there were no physical changes made to the activator furnaces.

In November 2006, Norit added a new waste heat boiler (WHB) downstream of the Secondary Carbonizer afterburners to produce steam for use at the plant. No direct or indirect emissions increases associated with the addition of this WHB were expected due to the fact that this equipment does not combust fuel and no debottlenecking occurred as a result of the addition of this equipment. The WHB generates steam through the transfer of heat from the hot exhaust stream from the Secondary Carbonizer to water flowing through a noncontact heat exchanger.

There are at least two EPA policy and guidance memorandums that address the applicability of BACT to downstream emission units. One is the 1989 Detroit Edison policy memorandum where EPA states that “The BACT requirement applies to each ‘proposed emissions unit at which a net emission increase would occur as a result of a physical change or a change in the method of operation of the unit [see 52.21(j)(3)].’ ” The policy memorandum reviews the PSD and BACT applicability to a project to burn an alternate fuel, natural gas, in a boiler at the Detroit Edison facility. The PSD determination found that even though the boiler could not accommodate combustion of natural gas prior to January 6, 1975 and required new burner canes, burning an alternate fuel did not constitute a physical change or change in method of operation that required a BACT review. This determination was based on the presumption that only the addition of burner canes would be required to burn natural gas and EPA’s historical position that

“...where the individual boiler being converted is capable of accommodating the alternate fuel, BACT would not apply.”

A July 28, 1983 memorandum also discussed the BACT requirement and its applicability to upstream and downstream units. The 1983 memorandum describes a process in which a pulp and paper mill installs a new bleaching plant and a larger digester. The installation of these two facilities did not itself result in an emissions increase. However, emissions at the recovery boiler downstream of the new and modified units increased. As stated in the memorandum, “Since the recovery boiler itself will not be undergoing a physical change or in the method of operation, it will not have to apply BACT.”

Given the discussions above, the scope of the BACT analysis herein covers only the Primary and Secondary Carbonizers, and only the control of emissions of SO<sub>2</sub> and NO<sub>x</sub>. The activator furnaces are not subject to BACT review because they did not experience a physical change or change in the method of operation as a result of the addition of the Primary Carbonizer. The Primary Carbonizer was installed to serve two important process functions: feed pre-treatment and commencing the initial oxidation and carbonization processes. The addition of the Primary Carbonizer allowed Norit to achieve a higher overall process yield and process a wider variety of coal. Even if the ability to process a wider variety of coal is believed to be a modification, EPA’s historical stance has been that if the emission unit being converted is capable of accommodating the alternate material without significant physical modifications, then BACT does not apply. Since the modification would add emissions of SO<sub>2</sub> and NO<sub>x</sub> above PSD levels of significance, the application has been determined to require full PSD review. Full PSD review consists of the following.

- A. Determination of Best Available Control Technology (BACT).
- B. Evaluation of existing air quality and determination of monitoring requirements.
- C. Analysis of compliance with National Ambient Air Quality Standards (NAAQS).
- D. Evaluation of PSD increment consumption.
- E. Evaluation of source-related impacts on growth, soils, vegetation, and visibility.
- F. Evaluation of Class I area impacts.

Step A analysis for NO<sub>x</sub> will be reviewed first, followed by Step A for SO<sub>2</sub>, then followed by Steps B through F for all pollutants.

## **A1 BACT for NO<sub>x</sub>**

### **Step 1 – Identification of all available control options**

In order to identify available control technologies, a search of US EPA’s RACT/BACT/LAER Clearinghouse (RBLC) was conducted to identify recent permitting actions and recent BACT determinations. First, the RBLC was searched for BACT determinations for the same emission unit and same process, then, for similar emission units and similar processes. As a final step, additional permitting files were reviewed to identify determinations that are not recorded in the RBLC database.

The RBLC was first searched for the terms: carbonizer; activated carbon; activation; activation furnace; and carbon. Only the search for “activation furnace” returned any results. However, these results were for munitions and explosives “deactivation furnaces” which is not a similar process or emission unit to those at the Pryor Facility.

The next step was to search the RBLC for listings for the same type of emissions units in “similar” processes. Four similar processes were identified for the purposes of this BACT review: carbon black manufacture, calcined coke manufacture, petroleum (needle) coke manufacture, and clay brick manufacture.

### ***Carbon Black Industry***

The carbon black industry is similar to the VAC production process in that a carbonaceous feedstock is heat-treated to create a saleable product (carbon black) that exhibits certain desired chemical properties. In the carbon black process, heavy oil is thermally reacted, resulting in the production of the carbon black product and also the generation of significant quantities of a waste gas (called “tail gas” by Cabot) that contains VOCs, sulfur compounds, and nitrogen compounds. The principal source of emissions in the oil furnace process is the main process vent, which is connected to the primary fabric filter unit (called the “main unit filter” by Cabot) that is used to separate the carbon black product from the tail gas stream. The main process vent stream therefore consists of the tail gas mixed with reactor quench water vapor. The volume and composition of these gaseous emissions vary considerably based on the grade of carbon black being produced. Gaseous emissions from the main process vent are controlled by combustion in boilers, thermal oxidizers, flares, and carbon black product pellet dryers. These combustion devices can achieve essentially complete oxidation of the VOCs contained in the tail gas, but the combustion process generates a considerable amount of NO<sub>x</sub> and SO<sub>2</sub> emissions due to the oxidation of the nitrogen and sulfur compounds in the tail gas, and NO<sub>x</sub> emissions attributable to the oxidation of nitrogen in the combustion air supplied to those combustion devices. NO<sub>x</sub> emission levels from the carbon black process are similar to those seen in the VAC production process and add-on NO<sub>x</sub> emission controls have not been required by regulatory agencies for these sources.

### ***Calcined Coke Industry***

The calcined coke industry is also similar to the VAC process in that a carbonaceous feedstock is processed in calciners at high temperature to drive off excess moisture and to create a dried product (calcined coke) that exhibits desired chemical properties. In the calcined coke process, petroleum coke from refinery coker units is used as the feedstock. Similar to VAC processes, some refinery coke used as feedstock is also combusted as part of the fuel source, in turn generating NO<sub>x</sub> emissions. The resulting tail gases from this process, therefore, contain significant quantities of NO<sub>x</sub> emissions that are orders of magnitude higher than those seen in the VAC production process. However, EPA has not required add-on NO<sub>x</sub> control for these sources, and add-on NO<sub>x</sub> controls are not used in this industry. This analysis suggests that additional add-on control may not be required as BACT for NO<sub>x</sub> emissions from the VAC production process.

### *Petroleum Coke Industry*

The petroleum coke industry is also similar to the VAC process in that a carbonaceous feedstock is processed in kilns at high temperature to drive off excess moisture and to create a dried product (needle coke) that exhibits desired chemical properties. In needle coke manufacturing, petroleum coke from refinery coker units is used as the feedstock. The petroleum coke process typically generates significant quantities of nitrogen dioxide from the combustion of the coke in the kilns. The resulting tail gases from this process contain significant quantities of NO<sub>x</sub> emissions that are orders of magnitude higher than those seen in the VAC production process. However, similar to what has been required for the calcined coke industry discussed above, EPA has not required add-on NO<sub>x</sub> control for these sources, and add-on NO<sub>x</sub> controls are not typically used in this industry. This analysis suggests that additional add-on control may not be required as BACT for NO<sub>x</sub> emissions from the VAC production process.

### *Clay Brick Industry*

Finally, the brick industry is similar to the VAC production process in that nonmetallic minerals are used as a feedstock. In the brick industry, clays (which are often mined in geologic formations that contain coal) are wetted and formed into bricks then fired in kilns at high temperature to drive off moisture from the brick and create the final product. From the dryer, the bricks enter the kiln for firing. There are several steps to firing the bricks in the kiln; evaporation of free water, dehydration, oxidization, and flashing. Flashing refers to the process of introducing uncombusted fuel into the kiln atmosphere in order to add color to the surface of the bricks. Most kilns are fired with natural gas, although coal, sawdust, fuel oil, and landfill gas are also used. Once the bricks have been fired, they are then cooled to ambient temperatures before they leave the kiln. Kiln fuel combustion and some dryer combustion activities result in the production of NO<sub>x</sub> emissions. In a manner similar to the VAC process, a small proportion of the raw clay material used in brick production combusts as fuel during the firing process, resulting in NO<sub>x</sub> emissions. NO<sub>x</sub> emissions from brick production processes are generally the same order of magnitude as those in the VAC process. As in the VAC industry, the brick industry is a “low margin” industry and the installation of add-on controls may compromise the viability of a particular plant. Many brick plants do not have add-on controls for NO<sub>x</sub>. This analysis suggests that add-on control may not be required for NO<sub>x</sub> emissions from the VAC production process to meet BACT.

The third step was to search the RBLC for BACT determinations for similar processes as described above using the search terms calciner, brick manufacturing, calcined carbon, calcined coke, and carbon black. The search returned results for only the terms “carbon black” and “calciner”. The Columbian Chemicals Corporation operates a carbon black reactor that minimizes the production of NO<sub>x</sub> emissions with good combustion practices. Degussa Engineered Carbons Corporation (DEC) operates several carbon black reactors for which a PSD-BACT review was performed. For these facilities, NO<sub>x</sub> controls were determined to be technically infeasible. The search for “calciner” provided results for several cement manufacturing companies and a soda ash production company. The results indicated instances of preheaters and calciner kilns for which NO<sub>x</sub> emissions were controlled through the use of either

good combustion practices or low- NO<sub>x</sub> burners. One cement company used the combination of a low NO<sub>x</sub> burner with selective non-catalytic reduction in their kiln.

RBLC search results for the previous categories follow. These lists identify the companies and processes found. BACT requirements, if any, have been discussed in the preceding paragraphs. More details may be found in Appendix C of the permit application.

**All RBLC Determinations for Process containing Carbon Black and NO<sub>x</sub> - Table 2**

RBLC ID	Facility	State	Update	Process Type	Process Type
OH-0287	Degussa Engineered Carbons	OH	5/27/2004	Rotary Tailgas And Natural Gas-Fired Dryer	69.015
AR-0045	Columbian Chemicals - El Dorado	AR	12/12/2002	Carbon Black Mfg., Units A, B, & C	69.015

**All RBLC Determinations for Process containing Carbon and NO<sub>x</sub> - Table 3**

RBLC ID	Facility	State	Update	Process Type	Process Type
KY-0070	NSA-A Division of Southwire Company	KY	5/29/1998	Carbon Bake Furnace	19.600
KY-0078	Meadwestvaco Kentucky LP - Wickliffe Carbon Plant	KY	11/16/1999	Woodbase Carbon Acid/Mixing, Activation Kiln	69.999
KY-0078	Meadwestvaco Kentucky LP - Wickliffe Carbon Plant	KY	11/16/1999	Drying Kiln, Specialty Thermal Carbon	19.600
CO-0040	American Soda, LLP, Parachute Facility	CO	5/6/1999	Sodium Carbonate Prod., Soda Ash Dryer, Nat. Gas	62.018

**All RBLC Determinations for Process containing Calciner and NO<sub>x</sub> - Table 4**

RBLC ID	Facility	State	Update	Process Type	Process Type
IA-0070	Lehigh Cement Company - Mason City Plant	IA	12/11/2003	Kiln/Calciner/Preheater	90.028
IA-0052	Lafarge Corporation	IA	7/1/2002	Cement Manufacturing Preheater/Precalciner Kiln	90.028
CO-0043	Rio Grande Portland Cement Corporation	CO	9/25/2000	Preheater/Precalciner, Kiln	90.028
MD-0027	Lehigh Portland Cement Company	MD	6/8/2000	Cement Manufacturing, Preheater/Precalciner Kiln	90.028
KS-0022	Monarch Cement Company	KS	1/27/2000	2 Precalciners (each)	90.028
WY-0034	Solvay Soda Ash Joint Venture Trona Mine/Soda Ash	WY	2/6/1998	Calciner, Natural Gas Fried Trona	90.017

**All RBLC Determinations for Process containing Activation Furnace and NO<sub>x</sub> - Table 5**

RBLC ID	Facility	State	Update	Process Type	Process Type
AL-0205	Anniston Chemical Agent Disposal Facility Field Office	AL	12/28/2004	Deactivation Furnace System	21.2
AL-0178	Anniston Army Depot - Chemical Weapons Incinerator	AL	1/9/2003	Deactivation Furnace	21.2
TX-0361	Equistar Chemicals,	TX	1/5/2005	Cat. Reactivation Furnace	19.6

The fourth step was to search the RBLC database for listings for similar emissions units irrespective of industry. Due to the unique nature of the thermal VAC production process, the RBLC database did not include any “similar” emission units. Therefore, for the purposes of this BACT analysis, a coal-fired boiler was considered to be a similar emission unit even though there are fundamental differences between carbonizers and coal-fired boilers. The primary difference is that in a coal fired boiler, the coal is almost completely consumed to provide heat. In VAC manufacturing, the process seeks to preserve the majority of the carbon in the coal and achieve the desired structure. Far less coal is combusted in a VAC process than in a similarly sized coal-fired boiler, resulting in much lower generation of NO<sub>x</sub> from combustion. A secondary difference is that the capacity of coal fired boilers is typically far higher than that of the carbonizers used by the Pryor Facility. Large coal fired boilers are expected to have a significantly higher emissions potential because the coal consumption of one 250 MMBtu/hr coal fired boiler is almost double the amount of coal used at the Pryor facility. The difference in emissions potential is significant not only on a mass emissions basis, but also on a pollutant concentration basis in that the exhaust of a coal-fired boiler is expected to have higher NO<sub>x</sub> emissions than the exhaust from a similarly-sized VAC process due to coal being the main source of fuel for a coal fired boiler, unlike the VAC process. This makes control methods more feasible for the boilers and not as feasible for the VAC process.

Despite these differences, coal fired boilers and VAC manufacturing both use coal as a raw material and the RBLC was searched for BACT determinations for coal fired boilers. Of the results returned for process type 11.110, coal-fired large utility boilers / furnaces (capacity greater than 250 million British thermal unit per hour (MMBtu/hr)), 29 coal fired boilers were identified in the RBLC database. The nitrogen oxide controls and/or control technologies that were determined to be BACT-PSD at the time of permitting action included six boilers with selective non-catalytic reduction / good combustion practices (one facility installed a CEM for monitoring), two boilers with low NO<sub>x</sub> burners/ good combustion practices, 6 boilers with low NO<sub>x</sub> burners/ Selective Catalytic reduction, one boiler with low NO<sub>x</sub> burners/ Selective Non-catalytic reduction, five boilers with Selective catalytic reduction, and two boilers with good combustion practices. The remaining seven boilers under the large utility boilers process type were not specifically noted as having nitrogen dioxide control required as BACT-PSD. These seven determinations were marked “N/A”, NSPS, or “other case-by-case determination.” The controls and/or control technologies on these boilers were: one boiler with selective non-catalytic reduction; one boiler with low NO<sub>x</sub> burners/ good combustion practices; one boiler with low NO<sub>x</sub> burners combined with selective non-catalytic reduction; one boiler with a CEM for NO<sub>x</sub> monitoring; and three boilers with no feasible controls.

A search was also performed on industrial sized boilers and furnaces (capacity between 100 and 250 MMBtu/hr) that were included in the RBLC database. The search returned three boilers in this category, showing one boiler with selective non-catalytic reduction and two boilers with good combustion practice determined to be BACT-PSD at the time of the permitting action. Finally, a search was conducted for commercial / institutional size boilers (capacity less than 100 MMBtu/hr). No search results were returned for this category.



RBLC search results for the previous categories follow. These lists identify the companies and processes found. BACT requirements, if any, have been discussed in the preceding paragraphs. More details may be found in Appendix C of the permit application.

**All RBLC Determinations for Process Code 11.110**  
**Large Coal Fired Boilers > 250 MMBTUH and SO<sub>2</sub> - Table 6**

<b>RBLC ID</b>	<b>Facility</b>	<b>State</b>	<b>Update</b>	<b>Process Type</b>
ND-0024	Great River Energy Spiritwood Station	ND	9/14/2007	Atmospheric Circulating Fluidized Bed Boiler
UT-0070	Desert Power Electric Cooperative Bonanza Power Plant Waste Coal Fired Unit	UT	8/30/2007	Circulating Fluidized Bed Boiler 1445
OK-0118	Western Farmers Electric Corporation Wygen 3	OK	2/9/2007	Coal-Fired Steam Boiler (Unit 2)
WY-0063	Black Hills Corporation	WY	2/5/2007	Boiler
NE-0041	Ag Processing, Inc. Agp Soy Processing	NE	9/11/2006	Unit 3 Boiler
WV-0024	Western Greenbrier Co- Generation	WV	4/26/2006	Circulating Fluidized Bed Boiler
MO-0071	Great Plains Energy Kansas City Power & Light Company	MO	1/27/2006	Pulverized Coal Boiler
MO-0071	Great Plains Energy Kansas City Power & Light Company	MO	1/27/2006	Pulverized Coal Boiler Unit 2
TX-0518	Valero Refining - Valero Heavy Oil Cracker	TX	11/16/2005	Emissions
VA-0296	Virginia Polytechnic Institute and State University	VA	9/15/2005	Operation Of Boiler
LA-0176	Louisiana Generating,	LA	8/22/2005	New 675 Mw Pulverized Coal Boiler
ND-0021	Montana Dakota Utilities/Westmoreland Power Gascoyne Generating Station	ND	6/3/2005	Boiler-Coal-Fired
NV-0036	Newmont Nevada Energy Investment	NV	5/5/2005	Coal Boiler
NE-0031	Omaha Public Power District	NE	3/9/2005	Unit 2 Boiler
MO-0060	City Utilities of Springfield - Southwest Power Station	MO	12/15/2004	Pulverized Coal Fired Boiler
WI-0228	Wisconsin Public Service Wps - Weston Plant	WI	10/19/2004	Super Critical Pulverized Coal Electric Steam Boiler
UT-0065	Intermountain Power Service Corporation - Power Generating Station	UT	10/15/2004	Pulverized Coal Fired Electric Generating Unit
UT-0064	Nevco - Sevier Power Company	UT	10/12/2004	Boiler With Dry Lime Scrubber
NE-0018	Hastings Utilities Whelan Energy Center	NE	3/30/2004	Boiler, Unit 2 Utility
WV-0023	Longview Power	WV	3/2/2004	Boiler,
SC-0104	Santee Cooper Cross Generating Station	SC	2/5/2004	Boiler No. 3 And No. 4
WI-0225	Manitowoc Public Utilities	WI	12/3/2003	Circulating Fluidized Bed Boiler (Electric Generation)
AR-0079	Plum Point Associates	AR	8/20/2003	Boiler
OH-231	First Energy Toledo Edison Co.	OH	7/31/2003	Boiler, Coke/Coal-Fired
TX-0491	Black Hills Corporation	TX	2/5/2007	No. 6 Power Boiler
TX-0489	Southwestern Public Service Company	TX	10/17/2006	Unit 3 Boiler
TX-0499	Sandy Creek Energy Associates	TX	7/24/2006	Pulverized Coal Boiler
MO-0071	Great Plains Energy Kansas City Power & Light Company	MO	1/27/2006	Pulverized Coal Boiler Unit 1 and Unit 2

**All RBLC Determinations for Process Code 12.110**  
**Large Coal Fired Boilers <250 MMBTUH and SO<sub>2</sub> - Table 7**

<b>RBLC ID</b>	<b>Facility</b>	<b>State</b>	<b>Update</b>	<b>Process Type</b>
ND-0020	Red Trail Energy, LLC Richardson Plant	ND	8/4/2004	Boiler, Coal Fired
VA-0267	VPI University Power Station	VA	8/30/2001	Boiler, Overfeed Stoker
OH-0241	Miller Brewing Company – Trenton	OH	5/27/2007	Boiler, (2) Coal Fired

Because the results of the RBLC searches were very limited, additional permitting documentation for the VAC process and similar processes was reviewed. The documentation reviewed included supporting permit documentation that is publicly available. The results of this review are presented in the following subsections.

***Virgin Activated Carbon Manufacturing***

The Pryor Facility manufactures VAC through a thermal re-agglomeration (TA) process. At the time of this BACT review, only two other United States facilities use the TA process to produce VAC, specifically, the Calgon Carbon Corporation's Catlettsburg, Kentucky and Bay St. Louis, Mississippi facilities. The permitting information gathered for the Calgon facilities indicated that their Carbonizers have not been required to install any controls for NO<sub>x</sub>. The Title V Permit for the Calgon Catlettsburg Facility represents a synthetic minor limit for NO<sub>x</sub> on their activation furnaces, which are not equipped with any add-on control devices.

As an additional point of reference, Cabot also owns and operates a thermal VAC process in Marshall, Texas. Although VAC is produced by a thermal process at the Marshall Facility, the process is inherently different in that it is a direct activation process, not a reagglomeration process. The Marshall VAC process employs rotating kilns and multiple-hearth furnaces (MHFs), but those units process raw material in a different manner and thus generate lower NO<sub>x</sub> and SO<sub>2</sub> emissions than do the kilns and MHFs in a TA VAC process. Notably, a PSD permit was issued in 2010 for an expansion of the Marshall Facility to construct six new MHFs, adding to the then-existing facility configuration of five kilns and one MHF. For that expansion project, the Texas Commission on Environmental Quality (TCEQ) required installation of low-NO<sub>x</sub> burners (LNBs) with flue gas recirculation for the afterburners serving the six new MHFs to comply with BACT for NO<sub>x</sub>. TCEQ did not require either LNB or any other NO<sub>x</sub> emissions control technology for the then-existing Marshall Facility kilns and MHF. Subsequent to this permitting, for the afterburner serving one of the new MHFs that had been built, the LNB was not manufactured to specifications and was unable to meet the applicable NO<sub>x</sub> emissions limit. Rather than replace the burner, Cabot retrofitted that one MHF afterburner with Selective Non-Catalytic Reduction (SNCR). This was not a BACT requirement imposed by TCEQ and in fact was not specifically required by TCEQ to address that issue, rather it was the best technically and economically feasible solution found by Cabot in that very specific situation to meet the NO<sub>x</sub> emission limit for that specific unit. TCEQ has not required SNCR for any similar units.

Therefore, of the three VAC facilities discussed herein, none of them has been required to employ add-on NO<sub>x</sub> emission controls to comply with BACT. However, several facilities were required to employ good combustion practices by the operational limitations section of their permits. Therefore, good combustion practices appear to be considered BACT for NO<sub>x</sub> emission control from a VAC process.

*Similar Processes*

This review identified three additional permitting actions for Degussa Carbon Black Plant in Baytown, Texas, Oxbow Carbon in Port Arthur, TX and Seadrift Carbon in Port Lavaca, TX that are relevant to this BACT analysis.

The Degussa Carbon Black Plant (DEC) in Baytown, Texas produces carbon black from an oil feedstock. This facility voluntarily self-disclosed historical NO<sub>x</sub> exceedances in their permit. As a result, the facility entered into a Compliance Agreement with the Texas Natural Resource Conservation Commission (TNRCC). Pursuant to a voluntary compliance audit performed by DEC under the Texas Environmental, Health, and Safety Audit Privilege Act, three issues related to emissions testing were disclosed by DEC. The disclosed issues included descriptions of instances in which total NO<sub>x</sub> emissions from the facility exceeded the maximum allowable emission rates in Permit No. 9294. Historical emission rates were calculated based on invalid technical assumptions and inappropriate emission factors. Since historical NO<sub>x</sub> emissions were under-represented by DEC, a retroactive PSD review of the previous projects was required. The projects undertaken by DEC since 1992 fell under the definition of pollution control projects and therefore did not require nonattainment NSR/PSD review since the increases do not contribute to an exceedance of the NAAQS. Therefore, nonattainment review was not required as part of this Compliance Agreement. No source reduction activities have been proposed for NO<sub>x</sub> emissions from this facility. The NO<sub>x</sub> emissions potential for this facility is generally comparable to that of the Pryor Facility. The DEC facility was not equipped with add-on NO<sub>x</sub> controls and Baytown subsequently shutdown all combustion units in August 2003.

Oxbow Carbon LLC, located in Port Arthur, Texas, is a calcining coke production plant that processes almost one million pounds of green coke a year. In 2006, Oxbow proposed new emission rates for Process Kiln 5 with a submittal of a Pollution Control Project standard permit, including proposed NO<sub>x</sub> emission rates exceeding 2,200 tons of NO<sub>x</sub> per year. This emissions potential is based on a review of the Maximum Allowable Emissions Rate Table (MAERT) for TCEQ permit numbers 5421 and 45622. The processing capacity of this facility is almost two orders of magnitude greater than the Pryor Facility and the emissions potential is almost 3 times the current emissions at the Pryor Facility. No add-on NO<sub>x</sub> controls were required by, or discussion of good combustion practices were included, within the requirements of the above referenced permits.

Finally, permit documentation for needle coke manufacturing was reviewed. Recent permitting documentation for the expansion of Seadrift Carbon in Port Lavaca, TX was located and reviewed. Seadrift Carbon increased their permitted calcining capacity from 27 tons per hour to 40 tons per hour. Process heaters at the facility were determined not to meet current BACT, but TCEQ agreed to allow them to meet 10 year old BACT because retrofit of the burners with controls could not be achieved without adversely affecting their product. Their unique process has allowed them to operate with the preexisting (i.e., non-low NO<sub>x</sub>) burners.

The review of additional permit documentation for similar processes revealed that 'no control' has been considered BACT for these processes. However, good combustion practices have been adopted to help reduce NO<sub>x</sub> emissions. These facilities process more raw material and have a

higher emissions potential than the Pryor Facility and add-on NO<sub>x</sub> controls have not been required.

***Summary of Step 1: Available Control Technology Options Considered in NO<sub>x</sub> BACT Analysis***

Based on the review of BACT determinations archived in the RBLC clearinghouse as well as additional permitting documentation, the following list of available control technologies was generated. These control technologies were reviewed in the remaining steps of the top-down BACT review.

- Selective non-catalytic reduction
- Selective catalytic reduction
- Low- NO<sub>x</sub> burners
- Good combustion practices

**Step 2 – Eliminate Technically Infeasible Options**

***Selective Non-Catalytic Reduction***

Applicant does not consider SNCR technically feasible for several reasons. Proper operation of SNCR requires that the emissions stream be within a specific temperature range for a minimum length of time, in order to complete the reaction between ammonia and NO<sub>x</sub>. According to EPA (Air Pollution Control Technology Fact Sheet EPA-452/F-03-031, July 15, 2003) the temperature range should be 1,600°F – 2,100°F. Manufacturers of SNCR advise that residence time should be at least two seconds. The only place in the exhaust stream that the temperature criterion can be met is in the anterior section of the afterburners for each carbonizer. The size of the afterburners, the immediate use of exhaust gases in waste heat boilers where cooling below the target range occurs, and the flow rate, mean that the residence time cannot be met. One further consideration has to do with pollutant concentration. The EPA document states that inlet concentrations of NO<sub>x</sub> should be above a threshold range of 200 - 400 ppmv. Although NO<sub>x</sub> concentration at the Secondary Carbonizer is approximately 270 ppmv, the concentration at the Primary Carbonizer is only 100 ppmv. While the concentration at the Secondary unit may be acceptable, the concentration at the Primary is too low, further emphasizing the infeasibility of SNCR for NO<sub>x</sub> reduction at the carbonizers.

***Low-NO<sub>x</sub> Burners***

Applicant does not consider LNB technically feasible for several reasons. First, applicant has found no LNB for which its manufacturer is willing to guarantee improved NO<sub>x</sub> emissions in this type of operation. Second, the flame produced in LNB is longer and wider than the flame produced in the current afterburners. If LNB, with or without flue gas recirculation were installed in the present geometry, the flame would likely impinge on the interiors, creating an inefficient combustion zone that will likely produce more emissions than are generated by the current afterburners.

**Step 3 – Rank Remaining Control Options Based on Effectiveness*****Selective Catalytic Reduction***

SCR can be designed to achieve NO<sub>x</sub> emissions reductions guaranteed by manufacturers up to 90%. Two configurations of SCR are analyzed here. One assumes individual SCR for each carbonizer stack, and the other assumes a single SCR for a combined stack for the two carbonizers. Each employs a ceramic honeycomb catalyst and urea as a reagent. While SCR is technically feasible, it presents certain challenges. It is not a demonstrated technology for VAC operations. Although its most common use in boilers involves exhaust streams similar to that encountered at the carbonizers, the operational requirements and economics for boilers are quite different from those for carbonizers, heightening the risk factor in extending SCR to VAC facilities. The relatively high level of sulfur in the carbonizer exhaust streams adds concern for fouling of the SCR catalyst, to the point of possible deactivation. In particular ammonium bisulfate is highly adherent and corrosive. Even if the only effect were to reduction of catalyst surface area, the resultant decrease in NO<sub>x</sub> reduction efficiency could be addressed only through taking the SCR out of service for cleaning, reducing the efficiency of the VAC facility.

***Good Combustion Practices***

Good combustion practices are employed currently to minimize, to the extent possible, NO<sub>x</sub> emissions from the Primary Carbonizer and Secondary Carbonizer. Thus this option was ranked lower than SCR relative to its potential effectiveness in reducing NO<sub>x</sub> emissions from those emissions units.

**Step 4 – Top-Down Evaluation of Control Options*****Environmental Impacts***

For SCR, emissions of H<sub>2</sub>SO<sub>4</sub> and ammonia are immediate consequences of this technology. Additionally, increased emissions of PM<sub>10</sub> and PM<sub>2.5</sub>, especially including ammonium bisulfate and ammonium sulfate, should be expected. Fouling or deactivation of catalyst is one problem associated with the latter compounds, as well as deposition on downstream equipment. The periodic replacement of solid catalyst produces an additional solid waste that would require additional handling. The management, treatment, and/or disposal of spent catalyst waste could potentially create new PM emissions from the Pryor Facility or the offsite facility that receives the waste catalyst.

***Economic Impacts***

The main economic impact of using the SCR system is that it would require a large volume of catalyst and reagent required for the reduction reaction. A catalyst management plan is required to determine the precise amount of catalyst needed to achieve the desired NO<sub>x</sub> reduction efficiency, as well as defining the schedule for reactivation or replacement of the catalyst when necessary.

Retrofitting existing equipment with SCR has higher capital costs than installing SCR on new process equipment. The magnitude of the cost differential is a function of the difficulty of the retrofit. The increase in cost is primarily due to making the modifications required to existing ductwork, the cost of structural steel and the construction of the reactor, auxiliary equipment costs (i.e., additional fans), and engineering costs. In addition, significant demolition and relocation of equipment may be required to provide space for the reactor. These costs can account for over 30% of the capital costs associated with SCR. Retrofitting of the Secondary Carbonizer and activator furnaces would have been required when the original construction occurred. The only difference would be the effect of inflation during the intervening years.

Detailed calculations for the annualized cost and cost effectiveness are contained in Appendix D of the 2014 updated application. The annualized cost of control for the operation of a SCR system for each Carbonizer was calculated to be \$1,776,675 per year. An approximately 90% reduction in NO<sub>x</sub> emissions would result in a 152 tpy reduction of NO<sub>x</sub> emissions, for an average cost of \$12,962 per ton. The annualized cost of control for the operation of a common SCR system to control both Carbonizers was calculated to be \$2,240,092 per year. An approximately 90% reduction in NO<sub>x</sub> emissions would result in a 152 tpy reduction of NO<sub>x</sub> emissions, for an average cost of \$16,343 per ton.

### *Conclusion*

Taking into account the significant operating cost, site-specific energy, environmental, and economic impacts, SCR is rejected as BACT for the Carbonizers at the Pryor Facility.

### **Step 5 – Selection of BACT**

Cabot does not believe that any of the add-on control technologies discussed above (SNCR, LNB, or SCR) is feasible for limiting NO<sub>x</sub> emissions from the Carbonizers for reasons cited in each of the analyses above. Good combustion practice is used widely in the VAC production industry to reduce emission of NO<sub>x</sub> and other pollutants that result from improper or inefficient combustion.

Therefore, good combustion practices in the operation of the carbonizers currently in place is selected as BACT. This has the effect of limiting emissions from the primary and Secondary Carbonizer without incurring prohibitive costs or adverse environmental impacts, as would be the case for an add-on control technology. NO<sub>x</sub> emission limits of 34.8 lb/hr and 152.3 tpy are proposed for the combined emissions from the Primary and Secondary Carbonizers that will vent to the atmosphere through the new stack, as described earlier in this Memorandum.

### **A2 BACT for SO<sub>2</sub>**

#### **Step 1 – Identification of all available control options**

For SO<sub>2</sub> control options, the identification process was very similar to the process used to identify NO<sub>x</sub> control options. For some details, reference should be made to the discussion above. The following section discusses aspects of this analysis that are specific to the identification of SO<sub>2</sub> control options.

***Carbon Black Industry***

SO<sub>2</sub> emissions from carbon black manufacturing are similar to those generated in VAC manufacturing in that they are attributable to sulfur contained in the process feedstock. While the SO<sub>2</sub> emissions generated by the carbon black process are typically orders of magnitude higher than those seen in the VAC production process, add-on SO<sub>2</sub> emission controls have not been required by regulatory agencies. Therefore, additional add-on control may not be required for the waste gases from the VAC production process to meet BACT.

***Calcined Coke Industry***

SO<sub>2</sub> emissions from calcined coke manufacturing are also similar to those generated in VAC manufacturing in that they are attributable to sulfur contained in the process feedstock. While the SO<sub>2</sub> emissions generated by the calcined coke process are typically orders of magnitude higher than those seen in the VAC production process, add-on SO<sub>2</sub> emission controls have not been required by regulatory agencies. Therefore, additional add-on control may not be required for the waste gases from the VAC production process to meet BACT.

***Petroleum Coke Industry***

SO<sub>2</sub> emissions from petroleum coke manufacturing are also similar to those generated in VAC manufacturing in that they are attributable to sulfur contained in the process feedstock. While the SO<sub>2</sub> emissions generated by the petroleum coke process are typically orders of magnitude higher than those seen in the VAC production process, add-on SO<sub>2</sub> emission controls have not been required by regulatory agencies. Therefore, additional add-on control may not be required for the waste gases from the VAC production process to meet BACT.

***Clay Brick Industry***

SO<sub>2</sub> emissions from clay brick manufacturing are also similar to those generated in VAC manufacturing in that they are attributable to sulfur contained in the process feedstock. The SO<sub>2</sub> emissions generated by the clay brick process are of a similar order magnitude higher as are those seen in the VAC production process. As in the VAC industry, the brick industry is a “low margin” industry and the installation of add-on controls may compromise the economic viability of a plant. Although many brick plants do not have add-on controls for SO<sub>2</sub>, a recent MACT standard promulgated by EPA has identified the need for hazardous air pollutant (HAPs) control from the brick kilns. One of the control technologies used, “dry lime injection” or “dry lime scrubbing”, also provides SO<sub>2</sub> control. In this control technology dry lime is added to the waste gases to react with the acid gases (hydrofluoric acid (HF) and hydrochloric acid (HCl)) in the waste stream. Although dry lime injection is primarily for HF and HCl control, there is also a realized SO<sub>2</sub> control efficiency.

The search for “calciner” provided results from the cement manufacturing industry. The results showed operations of preheaters and calciner dryers that controlled emissions of sulfur oxides with the use of either a scrubber or low sulfur in the feedstock. In this case, the use of a low

sulfur feedstock also constitutes a sulfur oxide “control device” via pollution prevention and was determined to be BACT-PSD on December 28, 2004.

RBLC search results for the previous categories follow. These lists identify the companies and processes found. BACT requirements, if any, have been discussed in the preceding paragraphs. More details may be found in Appendix C of the permit application.

**All RBLC Determinations for Process containing Carbon Black and SO<sub>2</sub> - Table 8**

RBLC ID	Facility	State	Update	Process Type	Process Type
OH-0287	Degussa Engineered Carbons	OH	5/27/2004	Rotary Tailgas And Natural Gas-Fired Dryer	69.015
OH-0287	Degussa Engineered Carbons	OH	5/27/2004	Carbon Black Units 3 And 4	69.015
OH-0287	Degussa Engineered Carbons	OH	5/27/2004	Carbon Black Units 1 And 2	69.015
TX-0389	Degussa Engineered Carbons	TX	12/31/2002	Carbon Black Process Caps	69.015
TX-0435	Cabot Corp. Development & Mfg. Ctr.	TX	12/31/2002	Reactor, Carbon Black	69.015
TX-0426	Cabot Corp. Pampa Plant	TX	12/16/2004	Reactor, Carbon Black	69.015
TX-0436	Degussa Engineered Carbons Borger Carbon Black Plant	TX	12/30/2004	Carbon Black Mfg	69.015
AR-0045	Columbian Chemicals – El Dorado	AR	12/12/2002	Carbon Black Mfg., Units A, B, & C	69.015
TX-0426	Cabot Pampa Plant	TX	12/16/2004	Reactor, Carbon Black	69.015

**RBLC Search Conducted: All RBLC Determinations for Process containing Carbon and SO<sub>2</sub> - Table 9**

RBLC ID	Facility	State	Update	Process Type	Process Type
KY-0070	NSA-A Division of Southwire Company	KY	5/29/1998	Carbon Bake Furnace	19.600

**RBLC Search Conducted: All RBLC Determinations for Process containing Calciner and SO<sub>2</sub> - Table 10**

RBLC ID	Facility	State	Update	Process Type	Process Type
IA-0070	Lehigh Cement Company - Mason City Plant	IA	12/11/2003	Kiln/Calciner/Preheater	90.028
IA-0052	Lafarge Corporation	IA	7/1/2002	Cement Manufacturing Preheater/Precalciner Kiln	90.028
CO-0043	Rio Grande Portland Cement Corporation	CO	9/25/2000	Preheater/Precalciner, Kiln	90.028
MD-0027	Lehigh Portland Cement Company	MD	6/8/2000	Cement Manufacturing, Preheater/Precalciner Kiln	90.028
IL-0057	Illinois Cement Company	IL	6/12/1998	Kiln, Cement, Preheater-Precalciner	90.028



**RBLC Search Conducted: All RBLC Determinations for Process containing Activation Furnace and SO<sub>2</sub> - Table 11**

RBLC ID	Facility	State	Update	Process Type	Process Type
AL-0205	Anniston Chemical Agent Disposal Facility Field Office	AL	12/28/2004	Deactivation Furnace System	21.2
AL-0178	Anniston Army Depot – Chemical Weapons Incinerator	AL	1/9/2003	Deactivation Furnace	21.2
TX-0361	Equistar Chemicals,	TX	1/5/2005	Cat. Reactivation Furnace	19.6

The next step consisted of searching the EPA RBLC database for similar emissions units, as above. The discussion parallels that for NO<sub>x</sub> above, as does the following discussion of large boilers, industrial boilers, and commercial/institutional boilers.

It was assumed that sulfur dioxide controls on coal fired boilers and furnaces could potentially transfer to Cabot's processes. The results showed the use of both wet and dry FGDs, and limiting sulfur input. These technologies remain on the list of those to be analyzed.

Because the results of the RBLC searches were very limited, additional permitting documentation for the VAC process and similar processes was reviewed. The documentation reviewed includes supporting permit documentation that is publicly available. The results of this review are presented in the following subsections.

***Virgin Activated Carbon Manufacturing***

As discussed above, other than the Pryor Facility there are only two other VAC manufacturing facilities in the United States that employ a similar TA process. The permitting information gathered for these two facilities, both of which are owned and operated by the Calgon Corporation, indicated that Carbonizers at both facilities are equipped with wet scrubbers. The Title V Permit for the Calgon Catlettsburg Facility represents a 75% SO<sub>2</sub> control efficiency for bakers (i.e., Carbonizers) that are equipped with wet scrubbers. The Calgon Bay St. Louis facility Title V Permit does not explicitly list the SO<sub>2</sub> control efficiency. However, it is expected that the wet scrubbers at the Calgon Bay St. Louis facility would achieve control similar to that represented for the Calgon Catlettsburg facility, given discussions with controls vendors. It should be noted that the Calgon Catlettsburg Facility is located in a portion of Boyd County, Kentucky that has been designated as an SO<sub>2</sub> non-attainment area. The language in the Calgon Catlettsburg Facility Title V permit statement of basis indicates that the scrubbers were installed for the purpose of demonstrating compliance with the SO<sub>2</sub> NAAQS, not for the purposes of meeting BACT. A review of the Sulfur Dioxide Redesignation Request prepared by the Kentucky Division of Air Quality and submitted to the USEPA in November 2004, confirms that the decrease in allowable emissions resulting from the installation of wet scrubbers from Calgon's Catlettsburg facility was the primary reason Boyd County was re-designated as attainment for SO<sub>2</sub>. This seems to indicate that the controls were installed for air quality standard attainment purposes, not for the purposes of BACT.

Cabot's Marshall Facility, which is discussed above employs a thermal process to manufacture VAC that is different from the TA process used at the Pryor Facility. All of the kilns employ wet

scrubbing, the older MHF employs wet scrubbing, and the new MHFs employ dry flue gas desulfurization (FGD). In the 2010 PSD permitting of the expansion of the Marshall Facility TCEQ required dry FGD for each of the six new MHFs to comply with BACT for SO<sub>2</sub>, and set limits in that permit on SO<sub>2</sub> emissions for those MHFs in terms of lb/hr and TPY, but not in terms of ppmv or lb/ton. TCEQ has not, however, required FGD for any of the kilns or the other MHF at the Marshall Facility. The wet scrubbers employed by the Marshall Facility kilns were in fact designed for control of PM emissions, not for control of SO<sub>2</sub> emissions. Although the wet scrubbing and dry FGD systems installed at Marshall are not parallel to what would be considered for SO<sub>2</sub> BACT for the Primary Carbonizer and Secondary Carbonizer at the Pryor Facility, both types of FGD were reviewed in this analysis.

Therefore, of the three other VAC facilities discussed herein, three facilities have add-on SO<sub>2</sub> emission control. One of those facilities appears to have added the wet scrubbing technology for NAAQS compliance, presumably as Lowest Achievable Emission Reduction (LAER) technology under the Nonattainment New Source Review (NNSR) regulations or attainment demonstration purposes under the Kentucky State Implementation Plan (SIP). The Marshall facility utilizes wet scrubbing for add-on SO<sub>2</sub> controls because it is an historical technology for the facility. The use of this add-on SO<sub>2</sub> control does not appear to be due to PSD permitting or as the result of a BACT review. The discussions above define wet scrubbing as an available control option.

### ***Summary of Step 1: Available Control Technology Options Considered in SO<sub>2</sub> BACT Analysis***

Based on the review of BACT determinations archived in the RBLC clearinghouse as well as additional permitting documentation, the following list of available control technologies was generated. These control technologies will be reviewed in the remaining steps of the top-down BACT review.

- Dry FGD, i.e., including limestone injection / lime scrubber
- Wet FGD
- Limit on process sulfur input

### **Step 2 – Eliminate Technically Infeasible Options**

While several of the available control options are technically challenging or have significant adverse economic or environmental impacts, none of them is technically infeasible. Adverse impacts are discussed in more detail below.

### **Step 3 – Rank Remaining Control Options Based on Effectiveness**

Following is a discussion of each add-on control option, presented in order based on their efficiency from an emission control perspective: (1) wet FGD, (2) dry FGD, and (3) process sulfur input limitation.

### *Wet Flue Gas Desulfurization*

Based on information provided by vendors, wet FGD is considered capable of guaranteed minimum SO<sub>2</sub> emissions reduction as high as 95%, making it the most effective available control technology for this analysis. That wet FGD is the most effective control is supported by the fact that the Title V permit for Calgon Catlettsburg Facility appears to indicate that in that case, wet FGD was found to represent Lowest Allowable Emission Rate (LAER) technology.

For the purposes of this BACT review, two wet FGD configurations were evaluated; one that included individual scrubbers on each Carbonizer stack and a second that involved installation of a common scrubber to serve both Carbonizers. In addition, given the high wastewater treatment costs for FGD blowdown, an innovative technology known as dual alkali scrubbing was evaluated based on the same configurations above. The vendor indicated that this dual alkali system can also achieve 90% control efficiency without generating any wastewater blowdown.

### *Dry FGD*

The next most effective add-on control technology was determined to be dry FGD, which is also referred to as limestone injection or dry limestone scrubbing. Based on information provided by vendors, dry FGD is considered capable of guaranteed minimum SO<sub>2</sub> emissions reduction as high as 90%. Similar to the consideration for the wet FGD options, this analysis included evaluation of individual FGD systems on each Carbonizer stack and a second configuration to install a common FGD system to serve both Carbonizers.

### *Limit on Process Sulfur Input*

Although not an add-on control technology, limiting the sulfur input to the VAC process to 150 pounds per hour was evaluated as potential BACT. This is equivalent to limiting the combined total sulfur content of the feedstock (coal and pitch) to 0.83%<sub>w</sub> when the feed rate to the process is 18,000 lb/hr, to 1.0%<sub>w</sub> when the feed rate to the process is 15,000 lb/hr, or to a correspondingly higher level when the feed rate is less than 15,000 lb/hr. Anecdotal information indicates that the feedstock at one of the Calgon facilities contains an average of 1.5% sulfur. Additionally, the RBLC clearinghouse contains records of BACT determinations that limited the sulfur content of the coal fired in carbon black manufacture to 3%. Finally, as another point of reference, the current coal feedstock sulfur content for Pryor contains an estimated average feedstock sulfur content of approximately 1%. Since the sulfur content of the feedstock currently used at the Pryor Facility appears to be the most stringent of the feedstock limits indicated for other facilities, the proposed limits will be evaluated during the following steps of the BACT analysis.

### **Step 4 – Evaluate Most Effective Controls**

According to top-down BACT protocol, the control options must be evaluated from most to least stringent control option. The most stringent control option that is not rejected is determined to be BACT. This section documents the review of the control options in the rank order determined in Step 3.

**Wet FGD**

Wet FGD to reduce sulfur dioxide emissions appears to be LAER for the Pryor Facility case, as it is the control option considered capable of the highest level of effectiveness. While wet FGD may achieve the highest level of control efficiency, installation of wet FGD at Pryor presents several challenges. Due to the locations of the two carbonizers to be controlled, either FGD must be installed on each carbonizer exhaust stack or a common ducting system must be constructed. The cost for the common ducting could be substantial and would require detailed engineering configuration of the site specific factors to accurately estimate costs associated with a single FGD system.

**Environmental Impacts**

The environmental drawbacks to wet FGD are the generation of wastewater in the form of scrubber blowdown and the scrubber sludge that is generated.

The blowdown issue is magnified for Pryor in that they discharge their wastewater to the existing publicly owned treatment works (POTW). In the past, Pryor faced challenges related to the selenium content in their wastewater. Selenium is a known aquatic toxic and discharges of selenium from Pryor and the POTW are restricted by permit limits. The wastewater resulting from wet FGD would likely increase the selenium loading to the POTW. In addition to requiring re-permitting for the Pryor Facility, the additional discharges of selenium may push the owner/operator of the POTW serving the Pryor Facility, the Oklahoma Ordnance Works Authority (OOWA), to their permit limit for selenium. The Pryor Facility would essentially utilize all remaining selenium capacity as a result of installing a wet FGD. It is unlikely that Cabot could successfully re-permit the Pryor Facility and continue to discharge to OOWA without major modifications.

Wet FGD also has several drawbacks from an emission control perspective. Wet FGD technology may generate additional PM emissions on the order of 1% associated with the solids created as a result of reaction between the scrubbing medium and the treated waste gas. Furthermore, the wet FGD technology may create condensable PM<sub>2.5</sub>, thereby creating additional air quality concerns given USEPA's PM<sub>2.5</sub> NAAQS. Finally, although wet FGD may be effective in reducing SO<sub>2</sub> emissions, an unintended effect of wet FGD, depending on the scrubbing medium is the potential production of sulfuric acid mist (H<sub>2</sub>SO<sub>4</sub>) due to the reaction of SO<sub>2</sub> with water.

Dual alkali scrubbing technology could be utilized to mitigate some of the negative environmental impacts of wet scrubbing. However, it too carries a negative environmental impact. A significant volume of filter cake is generated and requires on-site handling and off-site treatment and disposal.

**Economic Impacts**

Wet FGD is used as add-on SO<sub>2</sub> control at some of the VAC plants in the United States. However, the annualized costs associated with the wet FGD at the Pryor Facility appear to be prohibitive from an economic perspective. The technology is fraught with significant operating costs due to the need to dispose of the wastewater and wastewater solids generated, the cost to

purchase water as the scrubbing medium, water availability, the electricity required for pumping wastewater, and general maintenance required on a wet scrubber due to a propensity to “foul”. In addition, the capital costs associated with wet FGD are high due to the infrastructure needed for wastewater collection and treatment, the large footprint of the wet scrubbing equipment, and chemical handling facilities.

As mentioned above, the current design and configuration of the Pryor Facility cannot accommodate the scrubber effluent generated as a by-product of wet scrubbing and still meet POTW pre-treatment standards. Additional infrastructure would be needed for wastewater collection and treatment. When the cost of the infrastructure required to handle and treat the scrubber effluent is added to the cost of the scrubber, the capital investment required for the wet scrubber significantly increases. Although a detailed design was not prepared for the necessary wastewater treatment plant installations, the costs for wastewater treatment equipment are expected to be as expensive as the cost of the scrubbers themselves.

The annualized cost of control for the operation of a conventional (limestone reagent) wet FGD for each carbonizer was calculated to be \$3,861,214 per year for the PC, \$3,469,135 for the SC, and \$5,381,140 for the combined carbonizers. Baseline SO<sub>2</sub> emissions are calculated by using the current permit limit of 1,658 TPY, as allocated among the principal emission sources. This conservatively high number assures maximum removal numbers, thus minimizing cost per ton. Testing has been performed twice; by Metco in 2004, and by Air Hygiene in 2012. Selected values from these tests were chosen to assure conservatively high estimates of removal. In this instance, the Primary/Secondary/Activator ratios are taken to be 7.9/23.6/68.5, resulting in baseline emissions of 131/291/1,136 TPY, respectively. For the combined carbonizers, total baseline is 522 TPY. An approximately 95% reduction in SO<sub>2</sub> emissions would result in a 124 TPY reduction at the PC, for an average cost of \$31,030 per ton, a 371 TPY reduction at the SC, for an average cost of \$9,333 per ton and a 496 TPY overall reduction for an average cost of \$10,846 per ton.

Similar calculations for dual alkali wet FGDs, noting only 90% reduction, yield \$39,334/ton for the PC, \$12,256/ton for the SC, and \$14,986/ton for the combination.

## **Conclusion**

Taking into account the significant operating cost, site-specific energy, environmental, and economic impacts, wet FGD is rejected as BACT for the carbonizers at the Pryor Facility.

## ***Dry FGD***

The next most stringent control option is dry FGD, via limestone injection. This technology is commonly used as an effective control technology in coal fired boilers. However, given the low concentrations of SO<sub>2</sub> in the VAC process the level of control achieved is significantly less than that would be achieved through wet FGD.

## **Environmental Impacts**

Dry FGD generates a significant solid waste stream. Depending on which sources are controlled, the solid waste stream generation rate may exceed 1,200 tons per year. Due to the nature of the

materials handled, the waste stream would probably contain heavy metals, requiring dedicated equipment and safe handling procedures both onsite and offsite. Offsite procedures may include specialized treatment and disposal.

### **Economic Impacts**

Calculations similar to those performed for wet FGDs was performed, noting only 90% reduction, yield \$31,173/ton for the PC, \$9,001/ton for the SC, and \$13,888/ton for the combination.

### **Conclusion**

Based on taking into account the site-specific economic and environmental impacts, dry FGD is rejected as BACT for the carbonizers at the Pryor Facility.

### ***Limit on Process Sulfur Input***

Limiting the sulfur content for VAC manufacture to 150 pounds per hour is analyzed briefly as potential BACT. This method involves no adverse environmental or energy impacts. The economic impact was calculated by comparing baseline to the expected reduction, that is, 522 TPY less 291 TPY, and dividing by the increased cost due to higher specifications involved in purchasing appropriate coal for use. The net economic impact is approximately \$3,397 per ton of reduction.

### **Step 5 – Selection of BACT**

Cabot proposes to limit the sulfur input rate to the VAC process at the Pryor Facility to 150 lb/hr. This option was selected as BACT because of the available control technology options that are applicable and technically feasible for the Primary Carbonizer and Secondary Carbonizer, based on the rejection of wet FGD and dry FGD, this option was the only one with acceptable environmental, energy, and economic impacts.

### **B, C, D.      Air Dispersion Modeling**

#### **Facility Location**

The Plant is located approximately five (5) miles south of Pryor, Oklahoma, in the southwest quarter of Section 4, Township 20 North, Range 19 East, in Mayes County.

The purpose of this air quality analysis is to determine if Cabot's emissions of NO<sub>2</sub> and SO<sub>2</sub> cause or contribute to a violation of the applicable NAAQS and PSD increments based on EPA's and ODEQ's preferred model and available guidance. Per the guidance, this is accomplished with a two-step air dispersion modeling analysis: *significance analysis* and *full impact analysis*. The *significance analysis* considers only the emissions associated with the proposed project to determine if it will have a significant impact on the surrounding area. A *full impact analysis* is performed for each pollutant for which the project has a significant off-property impact.

### Significance Analysis

In a significance analysis, the project-related emissions increase is modeled for each pollutant that exceeds the significant emission rate and the maximum modeled ground-level concentration is compared to the corresponding significant impact level (SIL). The EPA requires that a NAAQS analysis be conducted if the project emissions result in maximum predicted concentrations exceeding a SIL. The facility impacts are also compared to the significant monitoring concentrations (SMC). If the project impacts exceed the SMC, pre-construction monitoring is required. A recent (January 12, 2013) court decision vacating the SMC for PM<sub>2.5</sub> stated that the CAA does not allow for exemptions from preconstruction monitoring. This decision also has implications for the SMC for other pollutants. Currently, AQD reviews all current ambient monitoring data and provides acceptable monitoring data to the applicant to satisfy the pre-application ambient air quality analysis requirements. The provided data is expected to be representative of the ambient air quality in the area of the affected facility. The following table lists the SILs, SMCs, NAAQS, and PSD increments for all NO<sub>2</sub> and SO<sub>2</sub> averaging periods.

**SIL, MDM, NAAQS, and PSD Increment Threshold Values - Table 12**

<b>Pollutant</b>	<b>Averaging Period</b>	<b>SIL (<math>\mu\text{g}/\text{m}^3</math>)</b>	<b>SMC (<math>\mu\text{g}/\text{m}^3</math>)</b>	<b>NAAQS (<math>\mu\text{g}/\text{m}^3</math>)</b>	<b>PSD Increment (<math>\mu\text{g}/\text{m}^3</math>)</b>
SO <sub>2</sub>	1-Hour	7.9	--	196.4	--
	3-Hour	25	--	1,300	512
	24-Hour	5	13	--	91
	Annual	1	--	--	20
NO <sub>2</sub>	1-Hour	7.5	--	188	--
	Annual	1	14	100	25

### Model Selection

The version of EPA's American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) used is 12345. AERMOD, a steady-state plume dispersion model used for assessment of pollutant concentrations from a variety of sources, is the primary model used for conducting refined regulatory modeling analyses. AERMOD incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain. AQD review of the modeling submitted included use of the most recent version of AERMOD (14134) and no significant changes in the modeled impacts were noted.

### Terrain

Following ODEQ guidance, modeling with elevated terrain was used for this analysis. AERMAP, a terrain preprocessor that incorporates complex terrain using USGS Digital Elevation Model (DEM) data was used to determine building and receptor elevations/hill heights. Stack elevations/hill heights were provided by ODEQ on February 24, 2014.

### Meteorological Data

Meteorological data for 2006 to 2010 obtained from the ODEQ was used for the modeling analysis. The data was generated using Integrated Surface Hourly (ISH) meteorological data from the Claremore NWS site (KGCM - ID# 722091). The meteorological data incorporated 5-minute surface data from the Pryor (Station No. 77) Oklahoma Mesonet<sup>®</sup> site. Oklahoma Mesonet<sup>®</sup> data was provided to the AQD courtesy of the Oklahoma Mesonet<sup>®</sup>, a cooperative venture between Oklahoma State University (OSU) and the University of Oklahoma (OU) and supported by the taxpayers of Oklahoma. The Springfield Regional Airport Station (SGF - ID# 13995) was used for upper air data.

### Monitor Data

Representative background concentrations provided by ODEQ on December 31, 2013, are shown below.

NO<sub>2</sub> Monitoring Data (Site ID: 40-109-9009):

**1-Hour NO<sub>2</sub> - Table 13**

<b>Year</b>	<b># Observations</b>	<b>98<sup>th</sup> Percentile</b>	<b>Impact (ppb)</b>	<b>Impact (µg/m<sup>3</sup>)</b>
2010	317	H7H	12.3	23.1
2011	282	H6H	14.0	26.3
2012	295	H6H	20.5	38.5
3 Year Avg.			15.6	29.3

**Annual NO<sub>2</sub>**

<b>Year</b>	<b># Observations</b>	<b>Impact (ppb)</b>	<b>Impact (µg/m<sup>3</sup>)</b>
2012	295	3.65	6.86

SO<sub>2</sub> Monitoring Data (Site ID: 40-109-9009):

**1-Hour NO<sub>2</sub> - Table 14**

<b>Year</b>	<b># Observations</b>	<b>98<sup>th</sup> Percentile</b>	<b>Impact (ppb)</b>	<b>Impact (µg/m<sup>3</sup>)</b>
2010	282	H3H	6.9	18.1
2011	315	H4H	8.5	22.3
2012	246	H3H	5.9	15.4
3 Year Avg.			7.1	18.6

**3-Hour SO<sub>2</sub>**

<b>Year</b>	<b>Value</b>	<b>Impact (ppb)</b>	<b>Impact (µg/m<sup>3</sup>)</b>
2012	H2H	5.0	13.09

SO<sub>2</sub> Monitoring Data (Site ID: 40-109-1037):



1-Hour NO<sub>2</sub> - Table 15

Year	# Observations	98 <sup>th</sup> Percentile	Impact (ppb)	Impact (µg/m <sup>3</sup> )
2010	349	H4H	6.0	15.7
2011	363	H4H	5.0	13.1
2012	361	H4H	5.0	13.1
3 Year Avg.			5.3	14.0

 3-Hour SO<sub>2</sub>

Year	Value	Impact (ppb)	Impact (µg/m <sup>3</sup> )
2012	H2H	4.0	10.47

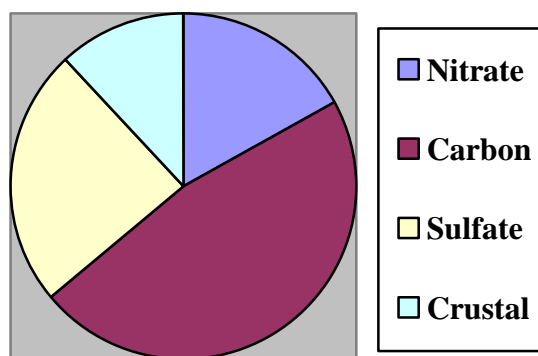
To reduce double counting of impacts from nearby SO<sub>2</sub> sources that were included in the modeling, the monitoring data from the Oklahoma City Monitor (40-109-1037) was used to demonstrate compliance with the NAAQS.

PM<sub>2.5</sub> Monitoring Data (Site ID: 40-109-9009):

The current guidance for PM<sub>2.5</sub> Modeling from EPA (454/B-14-001 May 2014) requires a assessment of secondary impacts of precursor emissions of NO<sub>2</sub> and SO<sub>2</sub> to include an assessment of the current ambient air concentrations of PM<sub>2.5</sub>.

 PM<sub>2.5</sub> Monitoring Data - Table 16

Year	# Observations	98 <sup>th</sup> Percentile	24-hr Impact (µg/m <sup>3</sup> )	Annual Impact (µg/m <sup>3</sup> )
2011	253	H6H	28.7	13.14
2012	308	H7H	21.5	10.04
2013	357	H8H	23.0	11.08
3 Year Avg.			24.4	11.42

 PM<sub>2.5</sub> Speciation


## Receptor Grid

The AERMOD analysis incorporates discrete receptors spaced 50 meters apart along the fence line of the Plant. Per the ODEQ Air Dispersion Modeling Guidelines, revised April 2011, five

(5) different rectangular grids made up of nested discrete receptors were used in the AERMOD modeling analysis. The ODEQ generally acceptable grid spacing of 100 m out to 1 km, 250 m out to 2.5 km, 500 m out to 5 km, 750 m out to 7.5 km, and 1 km out to at least 10 km from the plant fence line was utilized.

### **Building Wake Effect (Downwash)**

All emission point sources that are within 5L of a building or nearby structure, where "L" is the lesser of the nearby building's height or its maximum projected width, will be affected by downwash from nearby structures or buildings. Therefore, building downwash affects were accounted for in the modeling analysis. Building wake effects on each emission point were incorporated through the use of the BPIP-PRIME algorithm. BPIP-PRIME calculates all direction-specific building data required by the air dispersion model to enable it to include the appropriate building downwash algorithm into the calculations. The structure dimensions were then imported into AERMOD on an emission point-specific basis. Building dimensions are found in the Appendices to the application.

### **Facility Sources**

The modeling analysis includes facility wide total post-project emissions from all significant units emitting NO<sub>x</sub> or SO<sub>2</sub>. Modeled emission rates are based on emissions calculations presented in the PSD application submitted January 8, 2014. A summary of the modeled post-project emissions is presented in the following table. The project specific emission sources are shown in bold font.

### **Inventory Sources**

Inventory sources must be included in the model as part of the modeling analysis. NAAQS inventory sources were provided by ODEQ on October 7, 2013 and are summarized in the following table. The in-stack ratios provided in the Appendices to the application were used only in the NO<sub>2</sub> 1-hour NAAQS analysis. PSD increment inventory sources were provided by ODEQ on December 16, 2013 and are summarized in the Appendices to the application. Table 17 identifies sources used in succeeding tables by their ID number.

Table 17

ID	Description
713A	Existing Main Stack
713B	New Stack
PCHJ1	PC Heating Jacket 1
PCHJ2	PC Heating Jacket 2
PCHJ3	PC Heating Jacket 3
PCHJ4	PC Heating Jacket 4
PCHJ5	PC Heating Jacket 5
PCHJ6	PC Heating Jacket 6
SCHJ1	SC Heating Jacket 1
SCHJ2	SC Heating Jacket 2

ID	Description
SCHJ3	SC Heating Jacket 3
SCHJ4	SC Heating Jacket 4
AWPDRYER	Acid Wash Plant Dryer
KILN	Regeneration Kiln
BOILER	Cleaver Brooks LE600 Boiler
SCE	SC East
SCW	SC West
EACT	East Activator Furnace Stack
WACT	West Activator Furnace Stack

**Cabot Facility Wide Source Parameters and Modeled Post-Project Emissions - Table 18**

ID	X Coord (m)	Y Coord (m)	Elevation (m)	Emission Rate (lb/hr)		Height (m)	Temp. (K)	Velocity (m/s)	Diam. (m)
				NO <sub>2</sub>	SO <sub>2</sub>				
7I3A	294,580	4,012,651	189.67	125.34	144.40	42.67	644.26	36.88	1.83
7I3B	294,495	4,012,569	190.6	34.77	66.50	36.58	601.48	34.44	1.22
PCHJ1	294,498	4,012,593	190.98	0.13	0.01	12.19	699.82	2.73	0.46
PCHJ2	294,504	4,012,593	190.8	0.13	0.01	12.19	699.82	2.73	0.46
PCHJ3	294,510	4,012,593	190.6	0.13	0.01	12.19	699.82	2.73	0.46
PCHJ4	294,516	4,012,592	190.41	0.13	0.01	12.19	699.82	2.73	0.46
PCHJ5	294,521	4,012,592	190.26	0.13	0.01	12.19	699.82	2.73	0.46
PCHJ6	294,527	4,012,592	190.11	0.13	0.01	12.19	699.82	2.73	0.46
SCHJ1	294,547	4,012,606	190.01	0.25	0.00	7.92	699.82	2.73	0.46
SCHJ2	294,547	4,012,609	190.06	0.25	0.00	7.92	699.82	2.73	0.46
SCHJ3	294,547	4,012,612	190.12	0.25	0.00	7.92	699.82	2.73	0.46
SCHJ4	294,547	4,012,615	190.18	0.25	0.00	7.92	699.82	2.73	0.46
AWPDYER	294,522	4,012,559	189.84	0.59	0.01	15.24	355.37	26.79	0.40
KILN	294,499	4,012,675	192.14	1.97	4.88	28.04	349.82	15.52	0.76
BOILER	294,523	4,012,625	190.87	0.87	0.00	9.14	463.71	13.39	0.61

**Existing Cabot Source Parameters Used to Calculate Facility Wide Project Impacts For Cause & Contribute Analysis - Table 19**

ID	X Coord (m)	Y Coord (m)	Elevation (m)	Emission Rate (lb/hr)		Height (m)	Temp. (K)	Velocity (m/s)	Diam. (m)
				NO <sub>2</sub>	SO <sub>2</sub>				
SCE	294,558	4,012,594	189.53	-3.38	-15.70	23.55	1,220.37	6.77	1.23
SCW	294,555	4,012,594	189.58	-3.38	-15.70	23.62	1,263.15	7.51	1.20
EACT	294,552	4,012,645	191.52	-16.69	-29.10	38.15	1,198.15	15.34	1.52
WACT	294,548	4,012,646	191.79	-19.56	-29.10	38.20	1,210.37	14.43	1.52

Significant impacts for short-term averaging analyses are determined by comparing the five-year average highest first high modeled concentrations to the SIL. The significant impacts for annual averaging period analyses are determined by comparing the maximum annual average modeled value for each year to the annual SIL. If the highest modeled concentrations (highest first high) for the modeled pollutant in the significance analysis are below their respective SILs, further analysis is not required. If modeled impacts are greater than the SIL, a full impact analysis is required to demonstrate that the project neither causes nor contributes to any exceedances of the applicable NAAQS or PSD increment.

### **Significance Analysis**

As model results in the following table show, the SILs for all averaging periods for NO<sub>2</sub> and SO<sub>2</sub> were exceeded, and thus, a full impact analysis was performed. The full receptor grid was included in all modeling analyses. The significance analysis impact is greater than the SMC for the SO<sub>2</sub> 24-hour averaging period; thus, ambient monitoring must be addressed. As part of the modeling analysis, representative monitoring data was provided by ODEQ as indicated in the Monitoring Data Section.

Class II Significance Modeled Concentrations ( $\mu\text{g}/\text{m}^3$ ) – Table 20

Year	SO <sub>2</sub> 1-Hour	SO <sub>2</sub> 3-Hour	SO <sub>2</sub> 24-Hour <sup>2</sup>	SO <sub>2</sub> Annual <sup>2</sup>	NO <sub>x</sub> 1-Hour	NO <sub>x</sub> Annual
2006	122.8	79.5	23.7	3.9	92.6	5.9
2007	103.9	64.6	27.4	3.9	90.5	5.6
2008	140.8	68.7	30.4	3.7	106.0	6.1
2009	94.6	67.7	25.9	3.4	82.2	5.3
2010	125.4	95.0	30.7	5.1	97.1	6.1
<b>Maximum Modeled Conc.<sup>1</sup></b>	<b>140.8</b>	<b>95.0</b>	<b>30.7</b>	<b>5.1</b>	<b>106.0</b>	<b>6.1</b>
Significant Monitoring Concentration	--	13	--	--	--	14
Modeling Significance Level	7.9	25	5	1	7.5	1
<b>Full Impact Analysis Required?</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>

1) Highest first high impacts for all pollutants for all averaging periods.

2) Increment analysis only, NAAQS revoked.

### Full Impact Analysis

If a pollutant exceeds its respective SIL, a full impact analysis is performed to determine compliance with NAAQS and PSD increment standards. The first step in the full impact analysis is to determine the Radius of Impact (ROI). The ROI is the distance from the facility to the farthest receptor that shows an impact at or above the SIL for each pollutant and averaging period. However, to expedite the inventory collection process and to avoid delays associated with determining an ROI, Cabot requested and obtained from ODEQ an inventory of off-property sources within the conservative maximum radius of 50 km. The full impact analysis was performed using the entire receptor grid as required by ODEQ.

### Qualitative PM<sub>2.5</sub> 24-hour/Annual NAAQS Analysis

Project emissions increases of direct PM<sub>2.5</sub> emissions are less than the SER of 10 TPY, but the project emissions increases of both NO<sub>x</sub> and SO<sub>2</sub> precursor emissions are greater than or equal to their respective SERs of 40 TPY. Accordingly, a compliance demonstration using modeling for the direct PM<sub>2.5</sub> emissions was not required. However, an assessment of the potential impacts of the significant precursor emissions from the project was required.

In conformance with USEPA's May 2014 guidance, the accounting of the precursor (SO<sub>2</sub> & NO<sub>2</sub>) emissions impact on secondary PM<sub>2.5</sub> formation may be any of the following.

- Qualitative in nature.
- Based on a hybrid of qualitative and quantitative assessments utilizing existing technical work.
- A full quantitative photochemical grid modeling exercise. EPA anticipates that only a limited number of situations would require explicit photochemical grid modeling.

A qualitative analysis was conducted in this case. The analysis indicated that when combining (1) the estimated project emissions increases for NO<sub>x</sub> and SO<sub>2</sub> to which interpollutant trading ratios specified in the guidance were applied, and (2) the estimated project emissions decreases in PM<sub>2.5</sub>, there is an estimated actual decrease in PM<sub>2.5</sub> emission impacts. The interpollutant trading ratios for NO<sub>x</sub> and SO<sub>2</sub> precursor emissions are 100:1 and 40:1, respectively. The potential PM<sub>2.5</sub> emission increases from the NO<sub>x</sub> and SO<sub>2</sub> precursor emissions is approximately 5.3 TPY and 13.8 TPY, respectively. Based on potential PM<sub>2.5</sub> emission decreases of 53.5 TPY, the project resultant ambient impacts should decrease.

### NAAQS Analysis

To complete the NAAQS Analysis, the facility-wide post-project emissions were modeled simultaneously with the emissions from the nearby sources identified in the inventory provided by ODEQ. The background concentrations for the respective averaging periods were added to the modeled concentration for comparison with the NAAQS. The appropriate modeled concentration plus the monitored background was compared to the corresponding NAAQS to predict if the post-project emissions will cause or contribute to a violation of the NAAQS.

#### Plume Volume Molar Ratio Method

Modeling of NO<sub>x</sub> emissions in AERMOD can follow one of several application methods, each outlined in Section 5.2.4 of the *Guideline on Air Quality Models*. The use of the Tier 3 method Plume Volume Molar Ratio Method (PVMRM) in Section 5.2.4 was used in conducting the NO<sub>2</sub> 1-hour NAAQS analysis. PVMRM is incorporated in the AERMOD model as a non-regulatory default method, and has been previously approved for use by EPA Region 6 as an appropriate modeling option for use in determining NO<sub>2</sub> impacts from a facility. PVMRM considers the conversion of NO<sub>x</sub> emissions to NO<sub>2</sub> in the atmosphere on an hour by hour basis. For each hour, the volume of the source specific plume is calculated for that individual hour's meteorological conditions. Emissions of NO<sub>x</sub> are predominantly nitric oxide (NO), and ozone will oxidize the NO into NO<sub>2</sub> with the limiting factor being an equilibrium state that is usually established among NO, NO<sub>2</sub>, and ozone concentrations in the atmosphere. Of fundamental importance is the issue that an ozone-limited atmosphere will limit the amount of conversion of NO to NO<sub>2</sub>. The amount of available NO<sub>x</sub>, NO, and ozone and eventual conversion to NO<sub>2</sub> is determined by the plume volume. Use of this more refined NO<sub>2</sub> modeling technique was used to more accurately model NO<sub>2</sub> ambient concentrations. The following three variables are required to utilize the PVMRM method in AERMOD:

1. **In-stack NO<sub>2</sub>/NO<sub>x</sub> ratio.** Site-specific data was used for Plant sources, and an in-stack ratio of 0.5 was used for sources where the ratio was unknown. Off-property in-stack data was included in the inventory provided by ODEQ based on the following established ratios. For those off-site sources not included in the list below a value of 0.2 was used.

In-Stack NO <sub>2</sub> /NO <sub>x</sub> Ratios – Table 21	
Source Type	Ratio
4SLB Engines	0.35
2SLB Engines	0.50
4SRB Engines	0.05

<b>In-Stack NO<sub>2</sub>/NO<sub>x</sub> Ratios – Table 21</b>	
<b>Source Type</b>	<b>Ratio</b>
Turbines	0.20
Heaters/Boilers	0.10

2. **Equilibrium NO<sub>2</sub>/NO<sub>x</sub> ratio.** Per EPA guidance, the NO<sub>2</sub>/NO<sub>x</sub> equilibrium ratio was set to 0.90 (90%), the default equilibrium ratio value.

3. **Ozone Background Concentration.** The hourly ozone data was provided by ODEQ on June 12, 2013. The data were generated based on the 5 year average of Seasonal, hour of day (HOD), and day of week (DOW) values from the hourly monitoring data from the Cherokee Heights monitoring site (Site ID: 40-097-9014) from 2006 to 2010. The hourly data were processed using ProMoD. ProMoD (Processing Monitoring Data) is a macro enabled workbook developed by ODEQ to assist in the review and processing of monitoring data. ProMoD takes hourly monitoring data and separates each hourly value into seasonal, HOD, DOW datasets. From these datasets, a specified percentile value is generated for each Seasonal, HOD, DOW dataset for each year. The yearly values are then averaged and used to generate a continuous hourly data file containing the average specified percentile seasonal, HOD, DOW values for use in AERMOD. Graphs are provided in the workbook for each season and year and for the averaged seasonal data to allow for easier analysis of the data.

PVMMR is implemented in AERMOD by selecting the appropriate model options, entering the ambient equilibrium ratio, the NO<sub>2</sub>/NO<sub>x</sub> in-stack ratios, and the background ozone data, and exercising these options during model calculations for all sources.

As shown in the following table, modeled exceedances of the SO<sub>2</sub> 1-hour NAAQS and the NO<sub>2</sub> 1-hour NAAQS were predicted, and, therefore, a cause or contribute analysis was completed for both the SO<sub>2</sub> 1-hour averaging period and the NO<sub>2</sub> 1-hour averaging period.

**NAAQS Modeled Concentrations (µg/m<sup>3</sup>) – Table 22**

<b>Year</b>	<b>SO<sub>2</sub></b>		<b>NO<sub>2</sub></b>	<b>NO<sub>x</sub></b>
	<b>1-Hour<sup>2</sup></b>	<b>3-Hour<sup>3</sup></b>	<b>1-Hour<sup>4</sup></b>	<b>Annual<sup>5</sup></b>
2006	--	282.5	--	35.9
2007	--	173.4	--	37.4
2008	--	160.2	--	39.3
2009	--	250.5	--	34.7
2010	--	325.9	--	40.7
<b>Maximum Modeled Concentration</b>	<b>277.2</b>	<b>325.9</b>	<b>221.0</b>	<b>40.7</b>
<b>Background Concentration<sup>1</sup></b>	<b>14.0</b>	<b>10.5</b>	<b>29.3</b>	<b>6.9</b>
<b>Total Concentration</b>	<b>291.2</b>	<b>336.4</b>	<b>250.3</b>	<b>47.6</b>
NAAQS	196.4	1,300	188.0	100
<b>Cause/Contribute Analysis Required?</b>	<b>Yes</b>	<b>No</b>	<b>Yes</b>	<b>No</b>

1) Monitored background concentrations provided by ODEQ via email on 12/31/2013.

2) 5-year average of the 99<sup>th</sup> percentile of the annual distribution of the daily maximum 1-hour concentrations.

- 3) Highest 2<sup>nd</sup> high modeled concentration over 5 years.
- 4) 5-year average of the 98<sup>th</sup> percentile of the annual distribution of the daily maximum 1-hour concentrations.
- 5) Highest annual average concentration over 5 years.

### SO<sub>2</sub> 1-hour Cause or Contribute Analysis

A cause or contribute analysis was required due to the modeled exceedance of the SO<sub>2</sub> 1-hour NAAQS. To complete the cause or contribute analysis, plot files were generated for the post-project Cabot emission sources, each inventory source, and all other modeled sources. Next, it was determined at which receptors modeled exceedances had occurred. A second modeling analysis was conducted for only those receptors at which a modeled exceedance occurred. As part of the second modeling analysis, pre-project Cabot SO<sub>2</sub> emissions from the Secondary Carbonizer East (SCE), Secondary Carbonizer West (SCW), East Activator Furnace (EACT), and West Activator Furnace (WACT) were backed out from the model. This was done by modeling negative SO<sub>2</sub> pre-project emission rates along with the facility wide post-project Cabot emission rates, as shown in tables 18 and 19. The SO<sub>2</sub> NAAQS inventory sources were also included in the second modeling analysis. A daily maximum contribution file was generated using the AERMOD MAXDCONT output option to determine which sources were causing or contributing to the modeled violation. Modeled impacts from Cabot and each inventory source were paired with the receptors with modeled exceedances. This process is continued for each level of impact (4<sup>th</sup> high, 5<sup>th</sup> high, 6<sup>th</sup> high, etc.) until no modeled exceedances occur. This step in the analysis is necessary to determine if any paired modeled impacts result in Cabot's causing or contributing to a modeled exceedance beyond the standard 4<sup>th</sup> high modeled impact. The table below (23) displays every receptor for each level of impact (4<sup>th</sup> to 10<sup>th</sup> high) where Cabot's impact exceeds the SIL of 7.9 µg/m<sup>3</sup>. Table 23 also presents the total impact at each of those receptors (the allowable impact is 182 µg/m<sup>3</sup>) and shows whether or not a paired exceedance exists between Cabot's impact and the total impact. Table 23 shows that the facility's post-project emissions that exceed the SIL do not cause or contribute to any of the modeled violations of the SO<sub>2</sub> 1-hour NAAQS. A detailed summary of the SO<sub>2</sub> 1-hour cause or contribute analysis can be found in the modeling report submitted by Cabot with their application.

**SO<sub>2</sub> 1-hour Cause or Contribute Analysis Summary (µg/m<sup>3</sup>) – Table 23**

Rank	X Coord	Y Coord	Cabot Impact > SIL (7.9 µg/m <sup>3</sup> )	Total Impact <sup>1</sup>	Paired Exceedance?
4TH	294,500.00	4,012,800.00	17.1419	179.0234	No
	294,500.00	4,012,900.00	9.3764	173.2161	No
5TH	All Cabot impacts are less than the SIL.				
6TH	294,400.00	4,013,500.00	9.1317	146.5486	No
	294,400.00	4,013,400.00	7.9983	145.6172	No
7TH	294,500.00	4,012,800.00	9.9328	151.1286	No
	294,400.00	4,013,800.00	8.7581	136.1973	No
	294,400.00	4,013,700.00	8.4587	135.7455	No
8TH	294,500.00	4,012,800.00	21.0145	144.7754	No
	294,500.00	4,012,900.00	9.4337	138.6637	No
	294,400.00	4,013,600.00	8.5509	130.3252	No

Rank	X Coord	Y Coord	Cabot Impact > SIL (7.9 $\mu\text{g}/\text{m}^3$ )	Total Impact <sup>1</sup>	Paired Exceedance?
	294,400.00	4,013,500.00	7.9826	129.5103	No
9TH	294,500.00	4,012,800.00	11.0474	140.3776	No
10TH	294,500.00	4,013,500.00	9.2849	122.9713	No
	293,800.00	4,011,700.00	8.8183	123.3202	No
	294,500.00	4,012,900.00	8.1969	132.1421	No

Allowable impact = 182.4  $\mu\text{g}/\text{m}^3$

### NO<sub>2</sub> 1-hour Cause or Contribute Analysis

A cause or contribute analysis was required due to the modeled exceedance of the NO<sub>2</sub> 1-hour NAAQS. To complete the cause or contribute analysis, plot files were generated for the post-project Cabot emission sources, each inventory source, and all other modeled sources. Next, it was determined at which receptors modeled exceedances had occurred. A second modeling analysis was conducted for only those receptors at which a modeled exceedance occurred. Per guidance received from ODEQ via email on February 18, 2014, only the project-related sources and emissions have to be included in the review to determine if the project has a significant impact or cause or contributes to the modeled exceedance. The NO<sub>2</sub> NAAQS inventory sources were also included in the second modeling analysis. In addition, pre-project NO<sub>2</sub> emissions from the Secondary Carbonizer East (SCE), Secondary Carbonizer West (SCW), East Activator Furnace (EACT), and West Activator Furnace (WACT) were backed out from the model. This was done by creating a separate source group for the pre-project NO<sub>2</sub> emissions sources (SCE, SCW, EACT, and WACT) and modeling the emissions as positives. The total impact from this source group was then subtracted from the 7I3 (Cabot sources) source group to give the final net Cabot impact at each of the modeled receptors. This step was necessary due to a limitation of AERMOD that results in failed model analyses caused by the inability of PVMRM to handle negative emissions. Cabot sources and emissions rates that were included in the model are all found in Tables 18 and 19.

A daily maximum contribution file was generated using the AERMOD MAXDCONT output option to determine what sources were causing or contributing to the modeled violation. Modeled impacts from Cabot and each inventory source were paired with the receptors with modeled exceedances. This process is continued for each level of impact (8<sup>th</sup> high, 9<sup>th</sup> high, 10<sup>th</sup> high, etc.) until no modeled exceedances occur. This step in the analysis is necessary to determine if any paired modeled impacts result in Cabot's causing or contributing to a modeled exceedance beyond the standard 8<sup>th</sup> high modeled impact for NO<sub>2</sub> 1-hour.

A paired impact was found at a single receptor with a modeled exceedance at the 9<sup>th</sup> high modeled impact level. This was also the only receptor location in the 8<sup>th</sup> through 16<sup>th</sup> high modeled impact levels where Cabot's post-project emissions impact exceeds the SIL. Using fence line data provided by ODEQ on March 7, 2014, this receptor was found to be located within the property of Pryor Chemical Company (PCC). As such, a "hole" modeling analysis was performed in which the contributions from PCC's emission sources were removed from the total impact at that receptor as part of the cause or contribute analysis. In doing so the total impact at this receptor no longer exceeds the NAAQS and the paired exceedance is eliminated.



Therefore, Cabot does not cause or contribute to any of the remaining modeled violations of the NO<sub>2</sub> 1-hour NAAQS, as shown in Table 24. A detailed summary of the NO<sub>2</sub> 1-hour cause or contribute analysis can be found in the modeling report submitted by Cabot with their application..

**NO<sub>2</sub> 1-hour Cause or Contribute “Hole” Modeling Analysis Summary (µg/m<sup>3</sup>) – Table 24**

X Coord	Y Coord	Rank	Source Group			
			7I3ALL (All Sources)	7I3 (Cabot Sources)	PCC	Remaining Impact
295,300.00	4,013,200.00	8TH	187.7016	0.7439	93.8434	93.8582
		9TH	183.3264	8.5313	88.0536	95.2728
		10TH	174.6239	0.1925	64.8534	109.7705
		11TH	165.3861	1.4196	86.6565	78.7296
		12TH	158.0313	0.2020	72.4892	85.5422
		13TH	150.9219	0.0606	49.0060	101.9159
		14TH	144.0957	-0.0084	43.9302	100.1655
		15TH	140.0915	0.0203	55.5528	84.5388
		16TH	134.9805	0.1345	70.3752	64.6053

### Ozone Air Quality Analysis

For any pollutant exceeding its PSD significant emission level as part of a new construction, a PSD air quality impact analysis is required to demonstrate compliance with any applicable ambient air quality standards established for that pollutant. EPA regulates NO<sub>x</sub> as a precursor to tropospheric ozone formation. Ozone is unique because the EPA has not established a PSD modeling significance level (an ambient concentration expressed in either µg/m<sup>3</sup> or ppmv) for ozone. However, EPA has established an ambient monitoring *de minimis* level, which is different from other criteria pollutants, because it is based on a mass emission rate (100 TPY) instead of an ambient concentration (in units of µg/m<sup>3</sup> or ppmv).

**Comparison of Impacts to Monitoring Exemption Levels**

Pollutant	Monitoring Exemption Levels	Ambient Impacts
NO <sub>x</sub>	100 TPY of NO <sub>x</sub>	529 TPY NO <sub>x</sub>

Since, NO<sub>x</sub> emissions are greater than the 100 TPY monitoring significance level. Ozone pre-construction monitoring is required. The Mayes Monitoring Site (No. 40-097-9014) located 3.3 km ESE of the facility will provide conservative monitoring data in lieu of pre-construction.

2012-2014 Monitoring Data Summary	Monitor 40-097-9014 Concentration (ppm)		
Ranking	2012	2013	2014
Fourth High	0.084	0.065	0.060

As modeled, the potential increase in emissions of NO<sub>x</sub> is 529 TPY. OAC 252:100-8-35 requires an air quality impact evaluation for each regulated pollutant for which a major modification would result in a significant net emissions increase. No *de minimis* air quality level is provided for ozone. However, any net increase of 100 tons per year or more of NO<sub>x</sub> subject to

PSD is required to perform an ambient impact analysis. Methods for evaluating single source impacts on ozone concentrations are not consistent, due to the lack of availability of data at a refined level, readily available tools and EPA guidance. DEQ has evaluated the impact of the historical emission increase from the Norit facility using an existing air quality database generated for a SIP evaluation and the CAMx photochemical modeling system.

Oklahoma entered into Early Action Compact (EAC) agreements with EPA for the Tulsa and Oklahoma City metropolitan areas. Photochemical modeling evaluations were prepared in support of the agreements. These evaluations were conducted in accordance with EPA guidance and underwent an extensive public comment process and EPA review. The modeling was based on a two week episode beginning in Mid-August of 1999 and extending through the first week of September 1999. This episode was chosen both by virtue of being a prolonged period of high ozone concentrations and a reflection of the most common meteorological conditions that spawn high concentrations for Tulsa and Oklahoma City.

Modeling for the Norit facility was conducted using the EAC 2007 control case. Emissions to be modeled were calculated by adding the potential increases identified in the application to the 2007 grown emissions. Existing emissions from facility were subtracted from the total site potential in order to reflect the grown 2007 inventories used in the EAC data base.

Maximum impacts from the proposed increases are insignificant. NO<sub>x</sub> scavenging is projected to occur in the vicinity of the facility in Mayes County. A maximum 8-hour increase of 0.49 to 0.5 ppb was predicted from the site. As emissions from this historical evaluation are in existence, existing monitoring data reflects the increase and concentrations are below the standard.

### **PSD Increment Analysis**

PSD increment is the maximum increase in concentration that is allowed to occur above a baseline concentration for a pollutant. The baseline concentration is defined (for each pollutant and averaging time) as the ambient concentration that existed at the time the first PSD application affecting an area was submitted. The baseline date depends upon the county in which the facility is located and on the pollutant in question. Sources that contribute to emissions increases (or decreases) after the baseline date are obtained from the ODEQ and are modeled along with total facility-wide potential emissions to determine if the proposed project will cause or contribute to a PSD increment exceedance. A PSD increment analysis was performed to determine if the facility's post-project emissions cause or contribute to a violation of NO<sub>2</sub> annual and SO<sub>2</sub> 3-hour, 24-hour, and annual PSD increment when modeled in accordance with the available guidance. To complete the PSD increment analysis, the post-project emissions from the facility are modeled simultaneously with the emissions from the sources identified in the inventory provided by ODEQ. As shown below, a modeled exceedance of the NO<sub>2</sub> annual PSD increment was predicted, and therefore, a cause or contribute analysis was completed for the NO<sub>2</sub> annual averaging period. The Cabot sources and emission rates used in the PSD increment modeling analyses can be found in Table 18.

Class II PSD Increment Modeled Concentrations ( $\mu\text{g}/\text{m}^3$ ) – Table 25

Year	SO <sub>2</sub> 3-Hour	SO <sub>2</sub> 24-Hour	SO <sub>2</sub> Annual	NO <sub>x</sub> Annual
2006	280.0	67.7	15.4	30.9
2007	172.8	76.0	16.2	31.8
2008	157.2	74.5	14.7	34.7
2009	243.8	74.3	14.1	29.8
2010	319.3	72.3	17.0	34.6
<b>Maximum Modeled Conc.</b>	<b>319.3</b>	<b>76.0</b>	<b>17.0</b>	<b>34.7</b>
PSD Increment	512	91	20	25
<b>Cause/Contribute Analysis Required?</b>	<b>No</b>	<b>No</b>	<b>No</b>	<b>Yes</b>

- 1) Highest 2<sup>nd</sup> high modeled concentration over 5 years.
- 2) Highest annual average concentration over 5 years.

**NO<sub>2</sub> Annual Cause or Contribute Analysis**

A cause or contribute analysis was required due to the modeled exceedance of the NO<sub>2</sub> annual PSD increment. To complete the cause or contribute analysis, plot files were generated using AERMOD for the post-project Cabot emission sources, each inventory source, and all other modeled sources. Next, using the data contained in the plot files, it was determined which receptors in any of the five years modeled had modeled impacts above the NO<sub>2</sub> annual PSD increment of 25  $\mu\text{g}/\text{m}^3$ . Modeled impacts from Cabot and each inventory source were paired with the receptors with modeled exceedances. The following table shows that the facility does not cause or contribute to any of the modeled violations of the NO<sub>2</sub> annual PSD increment.

NO<sub>2</sub> Annual Cause or Contribute Analysis Summary ( $\mu\text{g}/\text{m}^3$ )

	X Coordinate	Y Coordinate	All Sources Avg Conc	Cabot Avg Conc	Inventory Sources Avg Conc
2006	295,200	4,011,200	30.9	0.5	30.4
	295,300	4,013,300	30.6	0.5	30.1
	295,300	4,013,400	27.9	0.6	27.3
	295,200	4,011,300	25.2	0.5	24.7
2007	295,300	4,013,300	31.8	0.5	31.3
	295,200	4,011,200	29.4	0.3	29.1
	295,300	4,013,400	28.7	0.6	28.1
2008	295,200	4,011,200	34.7	0.4	34.4
	295,300	4,013,300	29.1	0.4	28.7
	295,200	4,011,300	27.5	0.4	27.1
	295,300	4,013,400	27.3	0.5	26.8
	295,200	4,013,400	26.0	0.6	25.4
	295,200	4,013,300	25.8	0.6	25.2

	<b>X Coordinate</b>	<b>Y Coordinate</b>	<b>All Sources Avg Conc</b>	<b>Cabot Avg Conc</b>	<b>Inventory Sources Avg Conc</b>
2009	295,200	4,011,200	29.8	0.3	29.5
	295,300	4,013,300	27.6	0.5	27.1
	295,300	4,013,400	25.6	0.5	25.0
2010	295,300	4,013,300	34.6	0.5	34.2
	295,200	4,011,200	31.9	0.4	31.5
	295,300	4,013,400	31.5	0.5	30.9
	295,300	4,013,500	26.7	0.6	26.1
	295,300	4,013,200	26.3	0.4	25.9

### Class I Impact Analysis

PSD regulations require that a Class I area analysis be conducted for all proposed sources with potential for air quality impacts on a Class I area. Class I areas are federally protected areas for which more stringent air quality standards apply to protect unique natural, cultural, recreational, and/or historic values. If modeling results indicate impacts are below significant impact levels (SIL), then the project would not cause or contribute to an increment violation. The AERMOD modeling results in the following table demonstrate two averaging periods that exceed the SILs.

**AERMOD Class I Significance Modeled Concentrations ( $\mu\text{g}/\text{m}^3$ ) @ 50 km – Table 20B**

<b>Year</b>	<b>SO<sub>2</sub> 3-Hour</b>	<b>SO<sub>2</sub> 24-Hour<sup>2</sup></b>	<b>SO<sub>2</sub> Annual<sup>2</sup></b>	<b>NO<sub>x</sub> Annual</b>
2006	14.59	1.97	0.08	0.04
2007	14.61	2.01	0.08	0.04
2008	10.56	2.36	0.06	0.03
2009	10.41	1.65	0.06	0.03
2010	11.64	1.88	0.07	0.04
<b>Maximum Modeled Conc.<sup>1</sup></b>	<b>14.61</b>	<b>2.36</b>	<b>0.08</b>	<b>0.04</b>
Modeling Significance Level	1.0	0.2	0.1	0.1
<b>Full Impact Analysis Required?</b>	<b>Yes</b>	<b>Yes</b>	<b>No</b>	<b>No</b>

3) Highest first high impacts for all pollutants for all averaging periods.

Because the predicted impacts at 50 km for the SO<sub>2</sub> 3-hour and SO<sub>2</sub> 24-hour exceeded the significant impact levels, previous modeling conducted using CALPUFF and 2001, 2002, and 2003 MM5 data was reviewed to determine if a full impact analysis is required for the SO<sub>2</sub> 3-hour and SO<sub>2</sub> 24-hour Class I Increments. The modeling represented the proposed facility and no reductions were taken into account for changes in stack heights or for existing sources. CALPUFF results demonstrate compliance with the SILs.

**CALPUFF Class I Significance Modeled Concentrations ( $\mu\text{g}/\text{m}^3$ ) – Table 20C**

	<b>SO<sub>2</sub> 3-Hour</b>	<b>SO<sub>2</sub> 24-Hour<sup>2</sup></b>
<b>Maximum Modeled Conc.<sup>1</sup></b>	<b>0.73</b>	<b>0.17</b>
Modeling Significance Level	1.0	0.2
<b>Full Impact Analysis Required?</b>	<b>No</b>	<b>No</b>

- 1) Highest first high impacts for all pollutants for all averaging periods.

## **E. Evaluation of source-related impacts on growth, soils, vegetation, and visibility.**

### ***Growth Analysis***

Per U.S. EPA Guidelines, a growth analysis is required only “if the project would result in a significant shift of population and associated activity into an area - that is, a population increase on the order of thousands of people.” A temporary increase in the population of the immediate area may have occurred during the construction period of the Primary Carbonizer. However, the project did not result in a temporary or permanent significant population shift or increase. The number of net new jobs in the community was very small. Therefore, the applicant did not do a growth analysis.

### **Soils and Vegetation Analysis**

The Carbonizer project does not result in any off-property concentrations of criteria pollutants in excess of NAAQS or PSD increment standards. The project will result in relatively small ambient air concentrations for SO<sub>2</sub> and NO<sub>x</sub> from the on-site sources compared to off-site sources, as predicted by the model for source groups “ONSITE” and OFFSITE”. It has therefore been determined that additional analyses are not required.

### **Visibility Analysis**

Visibility analyses evaluate impacts of the proposed projects on any Class II areas within the AOI and on any Class I areas within 100 km of the proposed site. No such areas have been established within the specified distances from the Pryor Facility. All sources affected by the project will comply with applicable visibility and opacity requirements in Oklahoma regulations. Therefore, additional modeling for visibility impairment analysis is not required.

## **F. Evaluation of Class I Area Impacts**

A Class I PSD Area is defined as one of the following.

- International park
- A national wilderness area greater than 5,000 acres
- A national memorial park greater than 5,000 acres
- A national park greater than 6,000 acres

The State of Oklahoma contains one PSD Class I Area, the Wichita Mountains Wildlife Refuge. A map of the PSD Class I areas nearest to Pryor, OK is available in the permit application. The closest Class I area is the Upper Buffalo Wilderness Area, located in Arkansas, approximately 169 kilometers (105 miles) to the east-southeast from the Pryor Facility. Per ODEQ guidance, Class I visibility and increment analyses must be conducted if the sum of the PM<sub>10</sub>, SO<sub>2</sub>, and NO<sub>x</sub> emission increases in tons per year (tpy) exceed 10D, where D is the distance in kilometers

from the source. A PM<sub>10</sub> decrease of 362 TPY, an SO<sub>2</sub> increase of 553.4 TPY and a NO<sub>x</sub> increase of 528.7 TPY add to 1,082 TPY for all Pryor sources (decreases are not added). This total is less than the 10D total of 1,690, so no PSD Class I impact analysis is necessary.

#### Class I Impacts Analysis – Q/d

Pollutant	Project Emission Increases (TPY)
SO <sub>2</sub>	553.4
NO <sub>x</sub>	528.7
PM <sub>10</sub>	0.0
Total TPY Increase	1,082.1
Distance to Class I Area (km)	169.0
Q/d (TPY Change/Distance to Class I Area)	6.4
Result	< 10

## SECTION VI. GREENHOUSE GAS EMISSIONS

Greenhouse gas (GHG) became a regulated pollutant on January 2, 2011. The facility has conducted an evaluation to demonstrate that the addition of the Primary Carbonizer project did not result in a net emissions increase in excess of 75,000 TPY of carbon dioxide equivalents (CO<sub>2e</sub>). Pre-project average annual actual emissions of CO<sub>2e</sub> were calculated for the 1986-1987 period. All pre-project coal use was 100% sub bituminous. Knowing the actual amounts of coal and pitch inputs and the carbon content of each allows the calculation of actual carbon fed to the process. Further, knowing the product yield and the average amount of fixed carbon in the product yields the amount of carbon exiting the process. A material balance approach indicates that all remaining carbon is emitted. Ignoring incomplete combustion, stoichiometry reveals total carbon dioxide emissions. The following table summarizes the assumptions and the results.

#### TONS, except as noted

Parameter Measured	Subbituminous Coal	Pitch	Total
Raw Material Input	37,995	1,915	39,910
Average Carbon Content	72.7%	93.0%	
Carbon Input	27,622	1,781	29,403
Product Yield			9,897
Product Carbon Ratio			92%
Carbon Output			9,105
Carbon Lost (Emitted)			20,298
CO <sub>2</sub> Emissions			74,426

In addition to the straightforward calculation of combustion emissions of CO<sub>2</sub>, calculation of emissions of other pollutants with CO<sub>2</sub>-equivalents was performed. Emissions of N<sub>2</sub>O and CH<sub>4</sub> were calculated using factors for overfeed stokers from Table 1.1-19 of AP-42 (9/98) and CO<sub>2e</sub> conversion factors from *PSD and Title V Permitting Guidance For Greenhouse Gases*, EPA, November 10, 2010. Note that the AP-42 factors are based on coal combusted and not on only the carbon content of the coal; that is, the calculation is based on the difference between raw material input and product. This figure is based on overall yield and is averaged across both coal and pitch. Although the facility treated each input individually, the following table reflects the totals.

Parameter	N <sub>2</sub> O	CH <sub>4</sub>
Coal & Pitch Combusted	30,013 TPY	30,013 TPY
Emission Factor	0.04 lb/ton	0.06 lb/ton
Emissions	0.60 TPY	0.90 TPY
Conversion Factor	310	21
CO <sub>2</sub> e Emissions	186 TPY	18.9 TPY

Thus, the total of all pre-project CO<sub>2</sub>e emissions is 74,631 TPY.

Post-project potential to emit (PTE) CO<sub>2</sub>e emissions are based on the equivalent of a continuous raw material feed rate of 15,000 lbs/hr for 8,760 hrs/yr, because the 150 lbs/hr limitation on sulfur strongly implies the use of coal having 1% or less sulfur by weight. The permit contains a condition limiting coal feed to 65,700 tons per year. The method and factors used follow those used for the pre-project emissions. Because post-project coal use included bituminous and sub bituminous coal, an analysis of all coal has to be based on the average mix of coals used. Complicating this calculation is the fact that four bituminous coals have been used, each with slightly different characteristics. Figures from 2009 were used to establish some ratios and the results were applied to the restricted feed rate, yielding the following.

**TONS, except as noted**

Parameter	Bit 1	Bit 2	Bit 3	Bit 4	Subbit	Pitch	Total
Coal Input	509	6,514	14,799	18,811	6,194	3,335	50,161
Carbon %	55.95	50.32	62.05	62.30	50.88	60.4	
Carbon Input	284.5	3,278	9,183	11,719	3,152	2,014	29,630
Product							15,117
Product Carbon							92%
Carbon Output							13,908
Carbon Emitted							27,210
CO <sub>2</sub> Emissions							99,769

The next step calculates CO<sub>2</sub> equivalents in the same manner as was done for pre-project emissions, using the same factors.

Parameter	N <sub>2</sub> O	CH <sub>4</sub>
Coal & Pitch Combusted	35,044 TPY	35,044 TPY
Emission Factor	0.04 lb/ton	0.06 lb/ton
Emissions	0.7 TPY	1.1 TPY
Conversion Factor	310	21
CO <sub>2</sub> e Emissions	217 TPY	22.1 TPY

Total CO<sub>2</sub>e emissions from the two preceding tables are based on 2009 actual production data. Because the exact mix of coals to be processed after the project was complete could not have been forecast with any accuracy at the time, this actual mix provides a good basis for further analysis. Values calculated here are proportioned up to match the equivalent of a 15,000 lb/hr rate for 8,760 hrs/yr of the post-project facility. Thus,  $(99,769 + 217 + 22.1) \times (65,700 \div 50,161) = 130,987$  TPY of CO<sub>2</sub>e.

Finally, emissions from natural gas combustion in the Primary Carbonizer and afterburner are based on maximum burner capacity, which is 105.1 MMCF/yr for the primary and 70.1

MMCF/yr for the afterburner, or 175.2 MMCF/yr total. Emission factors are taken from Table 1.4-2 of AP-42 (7/98) and the CO<sub>2</sub>e conversions are as stated previously.

<b>Pollutant</b>	<b>Emission Factor Lb/MMCF</b>	<b>Emissions TPY</b>	<b>CO<sub>2</sub>e Factor</b>	<b>CO<sub>2</sub>e Emissions TPY</b>
CO <sub>2</sub>	120,000	10,512	1	10,512
N <sub>2</sub> O	2.2	0.19	310	59.7
CH <sub>4</sub>	2.3	0.20	21	4.23
Total				10,576

Total post-project CO<sub>2</sub>e emissions are 130,987 plus 10,576 = 141,564 TPY. Thus, the net emission increase is 141,564 minus 74,631 equals 66,933 TPY, well below the 75,000 TPY threshold requiring further analysis of CO<sub>2</sub>e emissions.

## **SECTION VII. OKLAHOMA AIR POLLUTION CONTROL RULES**

OAC 252:100-1 (General Provisions) [Applicable]  
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]  
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations listed in OAC 252:100, Appendix Q. These requirements are addressed in the “Federal Regulations” section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]  
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in “attainment” of these standards.

OAC 252:100-5 (Registration, Emissions Inventory and Annual Operating Fees) [Applicable]  
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories were submitted and fees paid for previous years as required.



OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]

Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the “Insignificant Activities” or “Trivial Activities” thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits.

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emissions limitations have been established based on information from stack testing, previous operating permits, and the permit application.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]

Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for affirmative defense, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Prohibition of Open Burning) [Applicable]

Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter (PM)) [Applicable]

Section 19-4 regulates emissions of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Fuel-burning equipment is defined in OAC 252:100-19 as any internal combustion engine or gas turbine, or other combustion device used to convert the combustion of fuel into usable energy. The natural gas combusted in the following equipment is subject to the requirements of this subchapter. Several of the afterburners at this facility vent their exhaust gasses to waste heat boilers. Although afterburners are typically considered to be pollution control equipment not subject to Section 19-4, in this instance they provide usable heat to the boilers and are subject to the Appendix C limits. Table 1.4-2 of AP-42 (7/98) lists total PM emissions for natural gas-fired external combustion units to be 7.6 lbs/million scf or about 0.0076 lbs/MMBTU, which is in compliance. Table 13.5-1 of AP-42 (9/91) suggests a range of values for “soot” from industrial flares. The afterburners’ exhausts fuel waste heat boilers, and smoky exhaust would cause fouling, so it is likely that the factor of zero µg/L is correct, but a conservatively high 20 µg/L is used to assure compliance. Exhaust rates and heat input are assumed at their various maxima.

Equipment	Maximum Heat Input (MMBTUH)	Emissions in lbs/MMBTU	
		Appendix C Limit	Potential Rate
PC Heating Jacket	8	0.60	0.008
SC Heating Jacket	10	0.60	0.008
East Activation Furnace	24	0.49	0.008
West Activation Furnace	24	0.49	0.008
Acid Wash Plant Dryer	3.3	0.60	0.008
PC Afterburner	12	0.60	0.008
SC Afterburner	18	0.60	0.008
Package Boiler	24.5	0.49	0.010*

\*Manufacturer supplied data

Section 19-12 limits particulate emissions from new and existing directly fired fuel-burning units and/or emission points in an industrial process based on process weight rate, as specified in Appendix G. As shown in the following table, all emission points are in compliance with Subchapter 19. Note that the primary and secondary carbonizing processes include two industrial processes each; namely, carbonizing and transporting. Additionally, the process weight for the carbonizing process includes raw material feed and process (reaction) air. The activation furnaces or multi-hearth furnaces (MHF) have three sections, each of which is subject to a limit. Process weight includes raw materials, reaction air, and steam. The East and West MHFs are identical in design.

Equipment	Process Rate (TPH)	Emissions (Lbs/hr)	
		Appendix G Limit	Potential Rate
Area 20 crusher	10	19.2	4.46 <sup>1</sup>
Area 20 compactor	10	19.2	
Area 20 bowl mill	10	19.2	
Area 40 product screen	4	10.4	0.035 <sup>2</sup>
Area 40 fines screen	2	6.52	0.017 <sup>2</sup>
Regeneration product screen	2	6.52	0.017 <sup>2</sup>
Drops (9)	20 each	30.5 each	0.022 <sup>2</sup> each
Drops (7)	4 each	10.4 each	0.004 <sup>2</sup> each
Drops (2)	2 each	6.52 each	0.002 <sup>2</sup> each
Truck unloading	20	30.5	0.002 <sup>2</sup>
Railcar unloading (2)	20 each	30.5 each	0.002 <sup>2</sup> each
Front end loader (5)	20 each	30.5 each	0.002 <sup>2</sup> each
Front end loader (3)	N/A	N/A	
Thermal dryer	10	19.2	0.05 <sup>1</sup>
Primary (carbonizing)	24	34.48	13.3 <sup>3</sup>
Primary (transporting)	8.6	17.33	
Secondary (carbonizing)	9.75	18.85	14.0 <sup>4</sup>
Secondary (transporting)	8.38	17.03	
MHF (combined)	57.04	61.58	24.5 <sup>6</sup>

Equipment	Process Rate (TPH)	Emissions (Lbs/hr)	
		Appendix G Limit	Potential Rate
MHF (combined)	57.04	61.58	24.5 <sup>6</sup>
Regeneration kiln	3.3	9.1	0.3 <sup>5</sup>
Acid wash plant	1.2	4.6	3.2 <sup>6</sup>

- 1 4/27/94 stack test
- 2 Table 11.19.2-2, AP-42 (8/04)
- 3 110% of 6/24/04 stack test
- 4 Combination of afterburner and WHB stack test results, 5/2009
- 5 9/15/95 stack test
- 6 Combination of stack and WHB stack test results, 5/5/2009

Emissions of PM from material handling and transport are very low in comparison to the allowable rate of emissions under this subchapter. No controls are required in the operating permit except for precautions taken to minimize fugitive dust.

OAC 252:100-25 (Visible Emissions and Particulates)

[Applicable]

No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. When burning natural gas in any of the combustion devices at the facility, there is very little possibility of exceeding these standards. The thermal dryer, crusher, compactor, and coal conveying, transfer, and loading equipment are not subject to Subchapter 25 since they are subject to an opacity limitation of NSPS Subpart Y. Various operations at the facility have emissions of certain pollutants controlled by afterburners, cyclones, or baghouses. The operating permit requires operation of these devices during operation of the related production equipment and requires appropriate maintenance of all control devices to ensure the opacity standard is met. The operating permit also requires weekly observation of the associated stacks, and opacity readings to be conducted if visible emissions are detected.

OAC 252:100-29 (Fugitive Dust)

[Applicable]

No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. The facility has numerous drop points and material processes. Normal operation of the facility with the control devices in operation should not cause a problem in this area. However, reasonable precautions to control fugitive dust emissions from the operations are stated in the operating permit.

OAC 252:100-31 (Sulfur Compounds)

[Applicable]

Part 5 limits sulfur dioxide emissions from new fuel-burning equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input averaged over 3 hours. The permit requires the use of natural gas as defined in Part 72 having 20.0 grains TRS/100 scf to ensure compliance with Subchapter 31.

The waste heat boilers need additional consideration. Note that in no case do the exhausts from such boilers exhaust directly to atmosphere; they are always commingled with direct exhaust from other sources. In any event, the waste heat boilers burn "alternative fuel," as that term is defined in §31-2. Because emission limits for SO<sub>2</sub> for these sources are covered by BACT requirements, the exhaust from each boiler is exempt from the requirements of Subchapter 31, per §31-25(4).

OAC 252:100-33 (Nitrogen Oxides) [Not Applicable]

This subchapter limits new fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to specified emissions of NO<sub>x</sub> in lbs per MMBTU, three-hour average. There are no equipment items that exceed the 50 MMBTUH threshold.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]

This subchapter affects gray iron cupolas, blast furnaces, basic oxygen furnaces, petroleum catalytic cracking units, and petroleum catalytic reforming units. There are no affected sources.

OAC 252:100-37 (Volatile Organic Compounds) [Part 7 Applicable]

Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. There are no tanks storing VOC that have capacity of 400 gallons or more.

Part 5 limits the organic solvent content of coating or other operations. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is not an affected operation.

Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize emissions. Temperature and available air must be sufficient to provide essentially complete combustion.

OAC 252:100-40 (Friable Asbestos During Demolition and Renovation) [May Be Applicable]

Any projects at the facility that involve asbestos removal are affected by this subchapter. Section 40-5 describes procedures for the proper handling of asbestos.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]

This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director. Since no AOC has been designated there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]

This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol

shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

**The following Oklahoma Air Pollution Control Rules are not applicable to this facility.**

OAC 252:100-10	General Operating Permits	not requested
OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-21	PM from Wood Waste Burning	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Municipal Solid Waste Landfills	not in source category

## SECTION VIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52

[Applicable]

Total emissions of NO<sub>x</sub> and SO<sub>2</sub> are greater than the threshold of 250 TPY of any single regulated pollutant, making it a major stationary source. A retroactive PSD analysis is shown in Section V above. Any future increases of emissions must be evaluated for PSD if they exceed a significance level.

NSPS, 40 CFR Part 60

[Subparts A, Dc, and Y Applicable]

Subpart A. This subpart contains general provisions that apply to all sources subject to requirements under Part 60. Design and monitoring requirements for flares are included, as well as general notification and reporting requirements. The various afterburners, if treated as flares, are not referenced in any subparts covering the facilities that they serve, so they are not affected by this subpart.

Subparts D, Da, and Db (Steam Generating Units) do not apply for various reasons. The waste heat boilers are not used to generate electricity and do not combust any fuel.

Subpart Dc (Small Industrial-Commercial-Institutional Steam Generating Units) applies to steam generating units constructed, modified, or reconstructed after June 9, 1989, and with maximum design heat input capacity greater than or equal to 10 MMBTUH and less than or equal to 100 MMBTUH. It does not apply to the waste heat boilers because they do not combust any fuel. The 24.5 MMBTUH boiler of EUG 20 is an affected facility and shall comply with SO<sub>2</sub> and particulate standards. This boiler uses only natural gas and is not subject to standards for either pollutant. Recordkeeping of daily fuel use is required by 40 CFR 60.48(g).

Subpart K, Ka, and Kb (VOL Storage Vessels). The 320 -gallon gasoline tank is not subject to any of these subparts because it is below the threshold capacity of each of these subparts.

Subpart Y (Coal Preparation Plants) affects thermal dryers, pneumatic coal cleaning equipment, coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems at coal processing plants with a capacity of 200 TPD or more and that commenced construction, reconstruction, or modification after October 24, 1974. All affected facilities are subject to an opacity limitation of 20% and the subpart prohibits discharge from any thermal dryer of gases with 0.031 gr/DSCF of PM or more. Pneumatic cleaning is not performed at this location. Performance testing has demonstrated compliance with all of these standards.

Subpart IIII (Stationary Compression Ignition Internal Combustion Engines {CI-ICE}) affects CI-ICE constructed, modified, or reconstructed after July 11, 2005. The emergency generator listed as an Insignificant Activity in Section IV went into operation prior to 1996, and is not an affected facility.

NESHAP, 40 CFR Part 61

[Not Applicable]

There are trace amounts of arsenic, beryllium, and mercury found in the raw coal, some of which is emitted to the atmosphere. Cabot's process does not fall under the applicability determinations of Part 61 for any of these pollutants. . There are no emissions of asbestos, vinyl chloride, coke oven emissions, or radionuclides. Testing has shown the raw material to contain insufficient amounts of benzene to trigger applicability of either Subpart J or Subpart FF

Subpart J (Equipment Leaks of Benzene) concerns only process streams that contain more than 10% benzene by weight.

Subpart FF (Benzene Waste Operations) concerns operations at chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries. This facility does not satisfy the definition of any of these activities, as described in 40 CFR 61.341.

NESHAP, 40 CFR Part 63

[Subpart ZZZZ Applicable]

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects RICE at major and area sources of HAP emissions. According to 40 CFR 63.6590(a)(1)(iii), the emergency generator engine listed in Insignificant Activities is an affected source, but according to §6590(b)(3), this existing emergency stationary RICE does not have to meet the requirements of Subparts ZZZZ or A, nor is initial notification required.

Subpart DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters), published in the Federal Register March 21, 2011, affects new and existing boilers at major sources of HAP. According to the definitions, waste heat boilers are not affected sources, because they do not combust fuel. The 24.5 MMBTUH NSPS Subpart Dc boiler of EUG 19 is an affected source. Subpart DDDDD defines "new" as any boiler whose construction or reconstruction commenced after June 4, 2010, so the Dc boiler is an existing source. Because this boiler burns commercial natural gas, it is within the category designated in 40 CFR 63.7499(l) as "Units designed to burn natural gas, refinery gas or other gas 1 fuels." Although the boiler is an affected source, there are no standards that apply to it at present, but initial notification is a requirement.

CAM, 40 CFR Part 64

[Not Applicable]

This part applies to any pollutant-specific emissions unit at a major source that is required to obtain an operating permit, for any application for an initial operating permit submitted after April 20, 1998, that addresses "large pollutant-specific emissions units," or any application that

addresses “large pollutant-specific emissions units” as a significant modification to an operating permit, or for any application for renewal of an operating permit, if it meets all of the following criteria.

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY

The Primary Carbonizer, Secondary Carbonizer, East activator furnace, West activator furnace, and the regeneration furnace use afterburners to control emissions of VOC and toxic compounds. However, emissions after control are below 100 TPY for these pollutants and these specific processes are not potentially subject to the CAM rule until the renewal Title V permitting date. PM controls added per the Consent Order will require a CAM applicability review during renewal Title V permitting.

The coal handling facilities, coal dryer, regeneration kiln and acid wash facilities utilize baghouses and fabric filters to control emissions of PM. However, emissions after control are below 100 TPY for these pollutants and these specific processes are not subject to the CAM rule until the renewal Title V permitting date.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]  
This facility does not process or store more than the threshold quantity of any regulated substance (Section 112r of the Clean Air Act 1990 Amendments).

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts B and F Applicable]  
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations that meet phase out requirements and that maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).

The facility performs service on motor (fleet) vehicles which involve ozone-depleting substances. Therefore, this facility is subject to these requirements and the permit requires compliance with Part 82 per Standard Condition XX.B.

## **SECTION IX. COMPLIANCE**

### **Inspection**

This retroactive PSD permit does not require an inspection independent from those performed in establishing the Part 70 operating permit.

### Testing

Performance testing of PM emissions following the installation of cyclones was completed over the period of May 5 through May 15, 2009. These tests were not performed to demonstrate compliance with regulatory limits or with authorized emissions, but comparison of the results with either set of standards indicates that measured emissions were less than any of the requirements. Tests were run under varying conditions and the following table shows only the worst-case results.

Source	Pounds per hour		
	Measured	Calculated <sup>1</sup>	Regulatory <sup>2</sup>
New Activator Furnace Stack	18.38	45.2	61.6
Activator Furnace Waste Heat Boiler	6.10	15.1	61.6
Secondary Carbonizer Afterburner	8.78	30.7	35.9
Secondary Carbonizer Boiler	5.22	30.7	35.9

1 See Emissions (Section III).

2 See Subchapter 19 discussion (Section VI).

### Tier Classification and Public Review

This application has been determined to be a Tier II based on the request for a construction permit for an existing major stationary source. The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land.

The applicant published the “Notice of Filing a Tier II Application” in *The Daily Times*, a daily newspaper in Mayes County, on February 10, 2008. The notice stated that the application was available for public review at the Pryor Public Library, Pryor, Oklahoma and at the AQD office in Oklahoma City. A notice of availability of the draft was published in *The Times*, a Mayes County newspaper, on August 24, 2014. The draft was available for review at the Pryor Public Library, Pryor, Oklahoma, at the AQD office in Oklahoma City, and on the Air Quality section of the DEQ web page at <http://www.deq.state.ok.us>. This facility is located within 50 miles of Oklahoma borders with Kansas, Missouri, and Arkansas. Notice of the draft permit was provided to each of these states. Concurrent public and EPA review resulted in only one comment.

Applicant requested that the statement “There are several active Air Quality compliance or enforcement issues, some of which are resolved by issuance of this permit, and some of which have no effect on the issuance of this particular permit” be removed from Section X of the memorandum. Because there are no active issues of this nature, DEQ agrees.

EPA had numerous comments, as follow.

1. It is noted that ten Activator Furnace startup events have been added to volatile organic compounds (VOC) emissions. Please explain why Startup, Shutdown and Malfunction emissions have not been evaluated and included for the other emissions.

Response: The same set of regulated air pollutants are emitted by the Activator Furnaces and



their afterburners during startup, shutdown, and malfunction periods as are emitted during normal operating periods. VOC and CO emissions will be higher during start up, while PM<sub>10</sub> and NO<sub>x</sub> will be higher during normal operations. Accordingly, the maximum emission rate specified in the permit and the start up conditions are appropriate to accommodate these operating conditions.

2. Please explain the basis on which total Lead emissions included in Table I on page 10 in the permit memorandum were calculated.

Response: Emissions of lead have historically been calculated by the applicant based on mass balance, identifying the characteristics of the raw material and of the finished product. This explanation will be added to the memorandum before issuance of the permit.

3. The post project feed rate quoted on pages 8 and 9 in permit memorandum is 78,840 TPY. However pages 45 and 46 in permit memorandum use a feed rate of 15,000 lbs/h for 8,760 hours per year to calculate greenhouse gas (GHG) emissions that works out to 65,700 TPY. Please explain why a lower post project feed rate was used to calculate GHG emissions on pages 45 and 46.

Response: In order to remain under the significance increase threshold for GHG emissions (i.e., 75,000 TPY), the annual input of feed to the Primary Carbonizer will be limited to 65,700 tons. The hourly input of feed to the Primary Carbonizer will be limited to 18,000 lbs/hr. The permit already requires that Cabot maintain records of production rates to demonstrate compliance with these limits. The language in the permit and memo has been modified to clarify this condition.

4. The baseline feed rate for the years 1987/88 quoted in permit memorandum pages 8 and 9 are 39,910 TPY and 46,429 respectively. Please explain the reason for using different baseline feed rates in the calculations on these two pages.

Response: The first number (39,910) is the feed rate to the primary carbonizer, and the second number (46,429) is the raw material handled in Area 20. Because the proper comparison is feed rate to feed rate, the memorandum calculation has been corrected to utilize the lower number.

5. Page 11 of permit memorandum states that the addition of the Primary Carbonizer, “was to increase VAC production capacity and allow the use of varying types of coal as VAC process feedstock. - - - Additionally, it is not believed that there was a change in the method of operation for any downstream process after the Secondary Carbonizer (i.e., the activator furnaces). This is due to the fact that EPA does not consider a change in feedstock a change in the method of operation if the emission unit was always capable of processing the feedstock.”

As presented in the permit memorandum on page 11, it is not clear whether Norit or ODEQ has recognized that if the installation of Primary Carbonizer (which was scope of the 1988 project) resulted in “increased utilization” of downstream units thus increasing emissions from those units. Project emissions should include emissions from any new equipment or emission increases from any changes to existing equipment, debottlenecking of any up-stream or down-stream equipment, or any increased utilization of support facilities. ODEQ admits that the feed conveyance system to the Secondary Carbonizer may be considered to have been modified as a

result of this 1988 project, arguably resulting in a modification to the Secondary Carbonizer. Clarification is needed to ascertain the actual amount of the projected overall emissions increase or decrease due to this project including details about increased utilization of support facilities if any.

Response: The effect of the installation of the Primary Carbonizer on upstream and downstream emissions of all regulated NSR pollutants that are emitted by the VAC plant was addressed in the PSD applicability determination. Please refer to page 11 of the Permit Memorandum which discusses that the emissions estimates on which the permit is based accounted for both pre-project and post-project emissions from sources throughout the VAC plant and not just the Primary Carbonizer and Secondary Carbonizer. This was done specifically because it was recognized that the emissions from certain upstream and downstream “linked units” may have been impacted by the installation of the Primary Carbonizer. More specifically, accounting was made of both pre- and post-project emissions from Area 10 (Materials Handling), Area 20 (Material Sizing and Drying), Area 30 (Activator Furnaces), and Area 40 (Finished Product Packaging). These are the only sources at the Pryor Facility whose emissions were potentially impacted by the installation of the Primary Carbonizer. The referenced wording is related to the need to do a BACT review for associated units based on EPA’s interpretation of “change in the method of operation.”

6. Please provide evidence to substantiate the suggestion by the facility’s consultant referenced on page 8 which states that the “emissions [of NO<sub>x</sub> and carbon monoxide (CO)] be treated as varying directly with the square of the production rate.”

Response: Reliable emission factors are not available, and the concept of linearity was discussed briefly in the memorandum. Several suggestions were offered for scaling up to higher production rates, and the extreme example of using the squared ratio was chosen as the conservatively highest of them. DEQ and the applicant recognize that the emissions resulting from this approach are improbably high, but feel this is a good faith solution to the difficulty.

7. The draft permit analysis states that the facility conducted an evaluation to demonstrate that the addition of the Primary Carbonizer project did not result in a net emissions increase in GHG emissions. The GHG analysis appears to have been completed based on a mass balance approach of the raw material feed (coal and pitch) combusted. In Section II, Facility Description, of the draft permit analysis, various natural gas-fired emission units are referenced in Areas 20 and 30 and the non-GHG emission increases or decreases are evaluated. Please provide additional information to clarify if the emission increases or decreases were included in the GHG analysis for natural gas-fired combustion sources.

Response: All gas-fired equipment in Area 30 was included in the calculations. Although coal is dried in Area 20, it is done so using waste heat. A package boiler added to the facility in 2005 was not a consideration in the 1988/89 timeframe relevant to this project.

8. The permit memorandum provides a listing of the in-stack ratios used in the applicant’s 1-hour NO<sub>2</sub> NAAQS analysis performed using PVMRM. ODEQ should insure that the permit record includes site-specific or equipment-specific information to support the modeled in-stack ratios for both on-site and off-site emission sources. Otherwise, an assumed default in-stack

ratio of 0.5 may be used for on-site and nearby off-site emission sources.

Response: Based on the recent EPA guidance “Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO<sub>2</sub> National Ambient Air Quality Standard” the default in-stack NO<sub>2</sub>/NO<sub>x</sub> ratio for distant (1-3 km) nearby sources is 0.2 and 0.5 for on-site sources and nearby sources in the immediate vicinity of the primary source. The guidance indicates the “paucity” of the data used to establish the EPA default in-stack ratio of 0.5. However, this data has never been published nor provided for public review.

The ODEQ, AQD continues to gather in-stack NO<sub>2</sub>/NO<sub>x</sub> ratios for different source types and for specific sources so that more accurate model predictions can be made. Based on the review of the accumulated in-stack NO<sub>2</sub>/NO<sub>x</sub> ratio data, the in-stack NO<sub>2</sub>/NO<sub>x</sub> ratios for nearby sources given in the tables are appropriate. The supporting data related to in-stack NO<sub>2</sub>/NO<sub>x</sub> ratios for all of the nearby sources in the NORIT modeling is too large for the permit record. The in-stack NO<sub>2</sub>/NO<sub>x</sub> ratio database and site specific or similar source stack test data related to the database is available for review. A large portion of this database has already been submitted to the EPA and is currently part of the EPA in-stack NO<sub>2</sub>/NO<sub>x</sub> ratio database. The ODEQ, AQD strives to collect and submit in-stack NO<sub>2</sub>/NO<sub>x</sub> ratios from recent testing as it becomes available.

The ODEQ, AQD still feels that the default in-stack NO<sub>2</sub>/NO<sub>x</sub> ratio is still too conservative for most sources. For the on-site sources the default value of 0.5 was utilized. In addition, NO<sub>x</sub> stack testing is required for significant on-site NO<sub>2</sub> emission sources.

9. The permit memorandum indicates that an assumed default in-stack ratio of 0.2 was used for off-site inventory sources that did not have source-specific or equipment-specific in-stack ratio information. While this approach is consistent with the most recent guidance provided by EPA for most off-site inventory sources, we believe that for nearby off-site sources, especially larger emission sources, that the assumed 0.5 in-stack ratio should still be used. The determination of nearby inventory sources will be case-specific, but we believe that a general rule of thumb may be used in most cases that would allow for off-site sources located outside the radius of impact of a facility to utilize the lower in-stack ratio of 0.2 while the nearby sources would be modeled with the assumed 0.5 in-stack ratio. The permit record should be updated to indicate the distance between the modeled off-site inventory sources and the Pryor Plant. For those sources determined to be nearby inventory sources, an assumed in-stack ratio of 0.5, instead of 0.2, should be used if source-specific or equipment-specific information is not available. If ODEQ has any questions regarding the determination of nearby sources, please contact Region 6 and we can address this case-specific determination.

Response: The ODEQ, AQD contests the presumption that all nearby sources in the immediate vicinity of the NORIT facility should use a default in-stack NO<sub>2</sub>/NO<sub>x</sub> ratio of 0.5 and specifically that the in-stack NO<sub>2</sub>/NO<sub>x</sub> ratio is singularly dependent on source size rather than type (i.e. larger sources have higher in-stack ratios). This disagreement is not only based on the “paucity” of the data supporting EPA’s presumption that the appropriate default in-stack NO<sub>2</sub>/NO<sub>x</sub> ratio should be 0.5 for nearby sources in the immediate vicinity of the primary source but also on the fact that the default in-stack ratio is not related to source type or operation. Based on the in-stack NO<sub>2</sub>/NO<sub>x</sub> ratio data ODEQ, AQD has collected to date, 0.2 is a more appropriate

value for a default in-stack NO<sub>2</sub>/NO<sub>x</sub> ratio and appropriate default ratios are dependent on source type and operation. The distance for all the nearby sources related to the NORIT facility can be discerned from the coordinates of the sources which have been provided.

10. Table 24 in the permit memorandum shows a negative value for the modeled impacts from “Cabot Sources.” Please provide additional information regarding why the modeled impacts from the proposed increases in NO<sub>x</sub> for the Pryor Plant would result in a decrease in ambient concentrations.

The permit memorandum states that the PVMRM approach is unable to handle modeled negative emissions. To clarify, none of the Tier I, II, and III (PVMRM/OLM) modeling approaches can include negative modeled emission rates. Tier I, II, and III approaches for modeling NO<sub>2</sub> are considered to be screening techniques and do not allow for the inclusion of negative emission rates since they would likely over predict ambient concentration “improvements” or increment expansions.

Response: As part of the project due to the new 1-hour NO<sub>2</sub> NAAQS, NORIT is replacing the existing stacks (SCE, SCW, EACT, & EACT) with new stacks (713A & 713B). These stacks are significantly higher than the previous stacks. In addition to modeling the new stacks at the proposed emission rate, the facility modeled the existing stacks using the historical emissions data prior to the project (baseline) separately. Negative emissions were not modeled. NORIT analyzed the modeled 1-hour NO<sub>2</sub> NAAQS impacts and determined that there was a single receptor at which the proposed facility with the new stacks would cause or contribute to a potential violation of the NAAQS. Table 24 is a summary of the cause or contribute analysis for this specific receptor. After reviewing the NAAQS modeling data, it was determined that this receptor was located on the property of the facility which had the greatest impact on that receptor. After removing the impacts of that facility from the total impacts of the receptor, it was determined that there would not be a violation of the NAAQS. However, in the analysis that was provided by NORIT they not only removed the impact of the facility at the receptor but also evaluated the project impacts at the receptor by subtracting out the baseline impacts which were modeled separately. For the 14<sup>th</sup> highest impact at that receptor, the difference of the impacts modeled for the proposed facility and the modeled baseline impacts were below zero. However, since the impacts at this receptor, after subtracting out the impacts of the facility whose property the receptor lies on, are below the NAAQS, a cause or contribute analysis of the NORIT facility was not required even though it indicated that the difference of the impacts of the modeled proposed facility would be less than the impacts of the pre-modification impacts.

11. The permit memorandum references a 2007 Class I analysis in lieu of a revised Class I analysis for the current permit action. The referenced 2007 analysis appears to rely on a Q/d approach using the SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub> emissions and the distance to the nearest Class I area. EPA has not proposed a Q/d approach for screening out sources from a Class I area SIP, NAAQS, or PSD increment analysis. Approaches using a Q/d screening technique are not appropriate technical analyses for evaluating the impacts from a source on a Class I area.

Please provide additional information to clarify what type of Class I analysis was completed in 2007 and why it would meet the Class I impacts analysis requirement for this PSD permit action

within the permit record. If only a Q/d screening technique was used previously, reliance on the 2007 analysis is not appropriate. Furthermore, it is unclear how a previous analysis would be representative of the current permit action, which includes NO<sub>x</sub> and SO<sub>2</sub> emissions increases.

Response: A complete Class I impacts analysis was completed by the applicant and submitted in April 2010. The memo failed to include the appropriate modeling summary results. The table in the memo was meant for the Class visibility review. The memo has now been updated to correctly reflect the 2010 modeling. All PSD Class I impacts were below their Significant Impact Levels (SIL).

12. The permit memorandum indicates that the proposed increase in NO<sub>x</sub> emissions associated with the project is approximately 528 TPY. Because NO<sub>x</sub> is a precursor for ozone, and the proposed emissions increases are above the threshold for ozone, the permit applicant should include an analysis to demonstrate compliance with the NAAQS for ozone. The permit record should be updated to include the ozone impacts analysis.

Response: An ozone analysis is included in the updated memo. This analysis demonstrates the facility is in compliance with the current standard.

13. The proposed permit grants Permit Shield in Section VI. The permit shield shall not extend to NSR construction permit or modifications. A source may request the permitting authority to include a permit shield in the title V permit under 504(f) of the CAA, and §70.6(f).

Response: Subchapter 8 of the ODEQ rules contains permitting requirements for both the construction and operation of major sources. In order to simplify the process and prepare the applicant for requirements and/or allowances under the Part 70 operating permit program, a single set of standard conditions was created. Some conditions/allowances of the standard conditions may not apply under the construction permit. Section VI is one of those. In order for the Permit Shield to apply the applicant must request such and the permit must contain a permit shield provision. The Cabot permit does not contain a Permit Shield provision as it is not allowed under a construction permit. Additionally, the regulatory citation clarifies that this provision is specifically for Part 70 permits.

#### **Fees Paid**

Significant modification to a major source permit fee of \$1,500.

## **SECTION X. SUMMARY**

Note that this permit is a retroactive PSD consideration of a completed project. This facility was constructed as described in the application. Issuance of this permit for significant modification is recommended.

**PERMIT TO CONSTRUCT  
AIR POLLUTION CONTROL FACILITY  
SPECIFIC CONDITIONS**

**Cabot Norit Americas, Inc.  
Pryor Activated Carbon Facility**

**Permit Number 98-171-C (M-2) PSD**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on December 5, 2007, with modeling and other information supplied at various times thereafter, in compliance with a Consent Order. The Evaluation Memorandum dated November 24, 2014, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. The following Specific Conditions are identical to those found in Part 70 operating permit 98-171-TV (M-8), except as modified for this project. All particulate matter (PM) emission limits are total PM, that is, filterable and condensable, or front-half and back-half, unless otherwise specifically indicated. Continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

1. Points of emissions and limitations for each point. [OAC 252:100-8-6(a)(1)]

**EUG 1 Facility-wide**

This emission unit group is facility-wide. It includes all emission units and is established to discuss the applicability of those rules or compliance demonstrations that may affect all sources within the facility.

**EUG 2 Primary Carbonizer, Afterburner, and Waste Heat Boiler**

<b>EU</b>	<b>Point ID</b>	<b>Name/Model</b>	<b>Const. Date</b>
17	SV-VP-005	Primary Carbonizer	1990

Emissions of NO<sub>x</sub> and CO were authorized by Permit No. 88-105-O, while authorized emissions of particulate matter, treated as PM<sub>10</sub>, and sulfur oxides, treated as SO<sub>2</sub>, derive from the Consent Order mentioned above. Note that the SO<sub>2</sub> amount is shared among the Primary Carbonizer, Secondary Carbonizer, and the multiple hearth furnaces (activator furnaces), also identified as EU 17 (EUG 2), EU 12 (EUG 3), EU 10 and EU 11 (Both in EUG 6). After construction of the current project, all emissions will have a limit that is common to EUG 2 and EUG 3.

**EXISTING LIMITS**

<b>Pollutant</b>	<b>NO<sub>x</sub></b>	<b>CO</b>	<b>PM</b>	<b>SO<sub>2</sub></b>
Lb/hr	11.3	1.07	N/A	N/A
TPY	49.3	4.67	204	1,658

**NEW LIMITS (EUG 2 and EUG 3)**

<b>Pollutant</b>	<b>NO<sub>x</sub></b>	<b>CO</b>	<b>PM<sub>10</sub></b>	<b>SO<sub>2</sub></b>
Lb/hr	34.8	3.97	77.4	66.4
TPY	152	17.4	339	291

- a. The permittee is authorized to operate the Primary Carbonizer at a maximum raw material weight short-term rate of nine tons per hour. [88-105-O]
- b. Sulfur, as elemental sulfur, input to the Primary Carbonizer shall not exceed 150 lb/hr, 24-hour average. [98-171-C (M-2)]
- c. Raw material input shall not exceed 65,700 tons of coal per 12-month rolling period. [98-171-C (M-2)]
- d. The Primary Carbonizer afterburner shall be operated: [88-105-O]
  - (1) at a temperature of not less than 1,650°F (three-hour average);
  - (2) with residence time of the stack gases in the afterburners at least 2 seconds;
  - (3) with annual calibration of temperature monitoring device;
  - (4) with annual burner inspection;
  - (5) continuously with the carbonizers; and
  - (6) using only natural gas as defined in Part 72 having 20.0 grains/100 scf or less total sulfur.
- d. Recordkeeping requirements are listed in SC #15. [OAC 252:100-8-6 (a)(3)(B)]
- e. The permittee will conduct annual testing for PM<sub>10</sub> and NO<sub>x</sub>. The test protocol will be submitted to DEQ for approval at least 30 days before the scheduled test date.
- f. Combustion gas flows for the Primary Carbonizer waste heat boiler stack, the Secondary Carbonizer waste heat boiler stack, and the Secondary Carbonizer afterburner stack will be combined into a new stack to be located south of the Primary Carbonizer. These gases will vent to atmosphere through the 6' diameter new stack at 120' above grade. The Primary Carbonizer waste heat boiler stack will be eliminated, and the other two stacks will be ducted to the new stack with the addition of an induced draft fan. An air quench system will be installed between the afterburner exhaust and the induced draft fan.
- g. The permittee will conduct performance testing for SO<sub>2</sub> and NO<sub>x</sub> within 180 days of completion of the stack reconfigurations designed to satisfy the requirements of this permit. Testing will demonstrate compliance with the BACT limits for each pollutant. Test protocols will be submitted to DEQ for approval at least 30 days before the scheduled test date. This initial NO<sub>x</sub> test may be used to satisfy one of the annual tests required by subcondition e above.

### EUG 3 Secondary Carbonizer, Cyclone, Afterburner, and Waste Heat Boiler

EU	Point ID	Name/Model	Const. Date
12	SV-VP-007a,b	Secondary Carbonizer	1979/2006*

\*Multiclones added 11/2006

Authorized emissions of all pollutants derive from the Consent Order mentioned above. Note that the SO<sub>2</sub> amount is shared among the Primary Carbonizer, Secondary Carbonizer, and the multiple hearth furnaces (activator furnaces), also identified as EU 17 (EUG 2), EU 12 (EUG 3), EU 10 and EU 11 (Both in EUG 6). After construction of the current project, all emissions will have a limit that is common to EUG 2 and EUG 3.

#### EXISTING LIMITS

Pollutant	NO <sub>x</sub>	CO	PM	SO <sub>2</sub>
TPY	103	12.7	135	1,658

## NEW LIMITS (EUG 2 and EUG 3)

Pollutant	NO <sub>x</sub>	CO	PM <sub>10</sub>	SO <sub>2</sub>
Lb/hr	34.8	3.97	77.4	66.4
TPY	152	17.4	339	291

- a. The Secondary Carbonizer afterburner shall be operated: [Consent Order]
  - 1) at a temperature of not less than 1,650°F (rolling three-hour average), with the inlet thermocouple used as the compliance monitoring point from the first introduction of solid feed into the carbonizer until the outlet thermocouple temperature reaches 1,650° or one hour, whichever comes first, and the outlet used as the compliance monitoring point thereafter;
  - 2) with annual calibration of temperature monitoring device;
  - 3) with annual burner inspection;
  - 4) continuously with the carbonizer; and
  - 5) using only natural gas as defined in Part 72 having 20.0 grains/100 scf or less total sulfur.
- b. The cyclone(s) shall be operated continuously whenever the waste heat boiler is being operated. The waste heat boiler and cyclone(s) may be bypassed. [Consent Order]
- c. The cyclones shall have external visual inspections to assure mechanical integrity and to identify any leaks (weekly).
- d. Recordkeeping requirements are listed in SC #15. [OAC 252:100-8-6 (a)(3)(B)]
- e. Combustion gas flows for the Primary Carbonizer waste heat boiler stack, the Secondary Carbonizer waste heat boiler stack, and the Secondary Carbonizer afterburner stack will be combined into a new stack to be located south of the Primary Carbonizer. These gases will vent to atmosphere through the 6' diameter new stack at 120' above grade. The Primary Carbonizer waste heat boiler stack will be eliminated, and the other two stacks will be ducted to the new stack with the addition of an induced draft fan. An air quench system will be installed between the afterburner exhaust and the induced draft fan.
- f. The permittee will conduct annual testing for PM<sub>10</sub> and NO<sub>x</sub>. The test protocol will be submitted to DEQ for approval at least 30 days before the scheduled test date.
- g. The permittee will conduct performance testing for SO<sub>2</sub> and NO<sub>x</sub> within 180 days of completion of the stack reconfigurations designed to satisfy the requirements of this permit. Testing will demonstrate compliance with the BACT limits for each pollutant. Test protocols will be submitted to DEQ for approval at least 30 days before the scheduled test date. This initial NO<sub>x</sub> test may be used to satisfy one of the annual tests required by subcondition f above.

**EUG 4 Primary Carbonizer Heating Jacket**

EU	Point ID	Name/Model	Const. Date
21	SV-VP-006	Primary Carbonizer Heating Jacket	1990

Emissions authorized by Permit No. 88-105-O for EU 21 were based on AP-42 factors and no authorized emissions were published for EU 21. This Part 70 does not set emission limits, but the equipment shall remain as it is and emissions shall be calculated using the most current AP-42 factors.

- a. All fuel burning equipment shall only be fueled with pipeline quality natural gas. [88-105-O]



b. Recordkeeping requirements are listed in SC #15.

[OAC 252:100-8-6 (a)(3)(B)]

### EUG 5 Secondary Carbonizer Heating Jacket

EU	Point ID	Name/Model	Const. Date
22	SV-VP-008	Secondary Carbonizer Heating Jacket	1979

Emissions authorized by Permit No. 88-105-O for EU 22 were based on AP-42 factors and no authorized emissions were published for EU 22. This Part 70 permit does not set emission limits, but the equipment shall remain as it is and emissions shall be calculated using the most current AP-42 factors.

b. All fuel burning equipment shall only be fueled with pipeline quality natural gas.[88-105-O]

c. Recordkeeping requirements are listed in SC #15.

[OAC 252:100-8-6 (a)(3)(B)]

### EUG 6 Activator Furnaces (Area 30)

EU	Point ID	Name/Model	Const. Date
10	SV-VP-009a, b	East Activator Furnace	1979
11	SV-VP-010a, b	West Activator Furnace	1979

Each furnace has a dedicated cyclone and afterburner, but they share a common exhaust. There are currently two stacks, one of which is identified as “new.” Following implementation of the project completion modifications, the existing “Activator Furnace Main Stack” will be employed to handle all emissions from the two activator furnaces. The current Activator Waste Heat Boiler Stack will be eliminated.

Authorized emissions of all pollutants derive from the Consent Order mentioned above. Note that the SO<sub>2</sub> amount is shared among the Primary Carbonizer, Secondary Carbonizer, and the multiple hearth furnaces (activator furnaces), also identified as EU 17 (EUG 2), EU 12 (EUG 3), EU 10 and EU 11 (Both in EUG 6). After construction of the current project, emissions from the two stacks will be combined into a single limit due to the common effluent from these stacks.

#### EXISTING LIMITS (TPY)

Unit Identity	NO <sub>x</sub>	CO	PM	SO <sub>2</sub>
Activator Furnace Main Stack	135	13.3	66.0	1,658
New Activator Furnace Stack	414	22.4	198	

#### NEW LIMITS (Combined stack)

Pollutant	NO <sub>x</sub>	CO	PM <sub>10</sub>	SO <sub>2</sub>
Lb/hr	125	8.15	60.3	144.5
TPY	549	35.7	264	633

- a. The east and west activator furnace afterburners shall be operated as follows.
  - 1) Natural gas (NG) shall be used during startup to bring the afterburner to a sustained temperature of at least 850°F before initiating material flow.
  - 2) After the afterburners become self-sustaining (no longer requiring NG), they shall be maintained at a temperature of not less than 1,650°F (three-hour average).
  - 3) Emissions of volatile organic carbon (VOC) during startup shall be calculated using the equation  $VOC \text{ (lbs)} = 0.95 \times (\text{feed rate in lbs/min}) \times (\text{volatile matter content as a decimal}) \times (t - 14.2\{\ln t + 14.2\}_0^t)$ , where t is in minutes, starting at initial material flow. The final value of t is determined by the time at which the afterburner temperature equals 1,650.
  - 4) Emissions of carbon monoxide (CO) during startup shall be calculated using the equation  $VOC \text{ (lbs)} = 0 + 38 + 2.81 \times (t - 87)$ , where t is in minutes, starting at initial material flow. The final value of t is determined by the time at which the afterburner temperature equals 1,650. The first term reflects the fact that there is no measurable flow of CO for the first 60 minutes. The second term reflects the rapid linear increase of CO flow over the next 27 minutes. The third term reflects the constant rate of 1,200 ppm of CO at maximum design flow of the exhausts.
  - 5) Startup is defined as the three-hour period following initial flow of material. Any emissions following three hours and before 1,650°F is reached shall be treated as excess emissions and reported per OAC 252:100-9.
  - 6) Annual calibration of temperature monitoring device
  - 7) Annual burner inspection
  - 8) Operated continuously with the carbonizers
  - 9) The afterburners shall be fueled during startup only with pipeline quality natural gas.
- b. The activator furnace heaters shall be fueled only with pipeline quality natural gas.
- c. The cyclones shall have external visual inspections to assure mechanical integrity and to identify any leaks (weekly).
- d. Recordkeeping requirements are listed in SC #15. [OAC 252:100-8-6 (a)(3)(B)]
- e. The existing activator furnace waste heat boiler stack will be eliminated, and emissions from the waste heat boiler will be ducted into the existing activator furnace main stack, which will be adjusted to a 6' diameter, and exhaust at 140' above grade.
- f. The permittee will conduct annual testing for PM<sub>10</sub> and NO<sub>x</sub>. The test protocol will be submitted to DEQ for approval at least 30 days before the scheduled test date

## EUG 7 Acid Wash Plant Dryer

EU	Point ID	Name/Model	Const. Date
23	SV-VP-015	Acid Wash Plant Dryer	1989

Emissions authorized by Permit No. 88-050-O (M-1) for EU 23 follow, updated to reflect current AP-42 factors for NO<sub>x</sub>, CO, and VOC.

Pollutant	NO <sub>x</sub>	CO	VOC	PM	SO <sub>2</sub>	HCl
Lb/hr	0.59	0.50	0.03	1.59	0.01	4.09
TPY	2.58	2.16	0.14	3.48	0.02	9.38

- a. The permittee is authorized to operate the Acid Wash Plant not to exceed production of 15,000,000 pounds per year of activated carbon. [88-050-O (M-1)]
- b. All air discharges from the dryer, bagging operation, screening operation, and associated conveying equipment shall be processed by a baghouse or an equivalent PM emissions control device with a design efficiency of 98% or more. [88-050-O (M-1)]
- c. The permittee shall maintain accessible monitoring equipment to verify that the pressure drop across the baghouse is within the range of 1" to 9" WC, 12-hour rolling average. Each one-hour rolling average of 10" or greater is an excess emission. [98-171-TV (M-5)]
- d. The dryer shall be fired only with natural gas having 4 ppm or less sulfur. [88-050-O (M-1)]
- e. Recordkeeping requirements are listed in SC#15. [OAC 252:100-8-6 (a)(3)(B)]

## EUG 8 Material Handling & Transfer – Controlled

EU	Point ID	Description	Throughput
24	SV-VP-004	Transfer of coal From Area 20 to surge bin	10 TPH

## EUG 9 Coal Processing Plant (Area 20)

Emissions from the Bowl Mill, Compactor, Crusher, Screener and Double Roll Crusher are processed by a single baghouse. Emissions from the coal dryer are processed by a separate baghouse.

EU	Point ID	Name/Model	Const. Date
8	SV-VP-002	Coal Preparation Plant Dryer	1994
9	SV-VP-003	Coal Preparation Bowl Mill	1994
9	SV-VP-003	Coal Preparation Compactor w/Crusher and Screener	1994
9	SV-VP-003	Coal Preparation Double Roll Crusher	1994

Particulate emissions authorized by Permit No. 93-025-O are as follow.

EU #	Equipment	Emissions	
		Lb/hr	TPY
8	Dryer	0.22	0.96
9	Preparation equipment	4.91	21.49

- b. The permittee shall comply with the Standards of Performance for Coal Preparation Plants, NSPS Subpart Y, for each thermal dryer, coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems in the Coal Preparation Plant. [40 CFR 60.250 *et seq*]
  - 1) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer gases which contain particulate matter in excess of 0.070 g/dscm (0.031 gr/dscf), or exhibit 20 percent opacity or greater. [§ 60.252(a)(1) & (2)]
  - 2) The owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater. [§ 60.252(c)]

- 3) The owner or operator shall install, calibrate, maintain, and continuously operate a monitoring device on the thermal dryer for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within  $\pm 3^{\circ}$  Fahrenheit and shall be replaced or recalibrated annually in accordance with procedures under §60.13(b). [§ 60.253]
- c. Raw coal input shall not exceed 240 tons per day (TPD), monthly average. [93-025-O (M-1)]
- d. The coal dryer shall be heated only with steam or other indirect heating such that no fuel-burning equipment becomes part of the unit. [93-025-O (M-1)]
- e. All air discharges from the coal drying, milling, crushing, and screening operations shall be processed by a baghouse or an equivalent PM emissions control device with a design efficiency of 99% or more. [93-025-O (M-1)]
- f. The permittee shall maintain accessible monitoring equipment to verify that the pressure drop across the Area 20 is within the range of 1" to 9" WC, and the coal dryer baghouse is within the range of 0" to 9" WC, 12-hour rolling average. Each one-hour rolling average of 10" or greater is an excess emission. [98-171-TV (M-5)]
- g. Recordkeeping requirements are listed in Specific Condition (SC)#15. [OAC 252:100-8-6 (a)(3)(B)]

#### **EUG10 Material Handling, Transfer, Traffic, & Erosion – Uncontrolled**

Note that subbituminous is truncated to “subbit” for this table.

<b>EU</b>	<b>Point ID</b>	<b>Description</b>	<b>Throughput</b>
1a	VP10-SUB-01	Subbit coal railcar unloading into hopper	20 TPH
1d	VP10-SUB-02	Subbit coal drop to elevator from unloading hopper	20 TPH
1e	VP10-SUB-03	Subbit coal drop from elevator to working subbit coal storage pile adjacent to unloading building	20 TPH
4	VP10-SUB-05	Front end loader drop into subbit coal storage pile in open storage area or in dry coal storage building	20 TPH
7	VP10-SUB-10	Front end loader drop of subbit coal into subbit coal loading hopper	20 TPH
2	VP10-PIT-01	Pitch railcar unloading into hopper	20 TPH
3	VP10-PIT-02	Pitch drop onto elevator from unloading hopper	20 TPH
1o	VP10-BIT-03	Bituminous coal unloading from truck into bituminous unloading pile	200TPH
1	VP10-BIT-05	Front end loader drop of bituminous coal into coal storage area or dry coal storage building	200 TPH
7	VP10-BIT-09	Front end loader drop of bituminous coal into Load Hopper	20 TPH
1	VP10-REC-03	Front end loader drop of Reclaim coal into truck	120 TPH
1	VP10-REC-05	Front end loader drop of Reclaim coal into Load Hopper	20 TPH
28	VP40-PACLD	PAC Bulk loading station into trucks	20 TPH
NA	SV-REGN-004	Truck unloading onto SAC storage pad	40 TPH
NA	REGN-SKUL	Regen F Hopper loading	3 TPH

**EUG 11 Acid Wash Plant Material Handling & Transfer – Controlled**

EU	Point ID	Description	Throughput
23	SV-VP-015	Acid wash dryer drop to product screener	1.5TPH
23	SV-VP-015	Acid wash screener drop to product bin	1.5TPH
23	SV-VP-015	Acid wash plant product packaging	1.5TPH

**EUG 12 Material Handling & Transfer – Controlled**

EU	Point ID	Description	Throughput
3	SV-VP-001	Pitch drop from elevator onto pitch building distribution conveyor belt	35 TPH
3	SV-VP-003	Pitch drop into Pitch feed Bin	20 TPH
13	SV-VP-012	Activated carbon from activated furnaces transfer into product screener and screening	4 TPH
13	SV-VP-012	Fines transfer from product screener to fines bin	4 TPH
13	SV-VP-012	Fines transfer from product screener to oversize bin	4 TPH
20	SV-VP-013	Transfer activated carbon from fines bin into PAC mill	4 TPH
13	SV-VP-012	PAC mill to packaging	4 TPH
13	SV-VP-012	Product screener transfer into packages	4 TPH
9	SV-VP-003	Activated carbon transfer into acid wash feed hopper	4 TPH
NA	Mobile Equipment	Pneumatic transfer of product from tanker to rail car	8 TPH

**EUG 13 Material Handling, Transfer, Traffic, & Erosion – Uncontrolled**

EU	Point ID	Description	Throughput
4	VP10-SUB-04	Front end loader transfer from working storage to open subbituminous storage or dry coal storage building	20 TPH
5	VP10-SUB-06	Front end loader maintenance of subbituminous open coal storage area or dry coal storage area or dry coal storage building including transfer between open and dry coal storage building and to subbituminous coal loading hopper	20 TPH
4	VP10-SUB-07	Wind erosion of subbituminous coal working storage pile	
6	VP10-SUB-08	Wind erosion of subbituminous coal storage pile	
6	VP10-SUB-09	Wind erosion of subbituminous coal storage pile in dry coal storage building	
3	VP10-PIT-06	Front end loader maintenance of pitch and transport to load hopper	20 TPH
1m	VP10-BIT-01	Travel by truck carrying bituminous coal on unpaved road (Loaded)	
7	VP10-BIT-02	Travel by truck carrying bituminous coal on unpaved road (Empty)	
5	VP10-BIT-04	Movement of bituminous coal from unloading area to coal storage area or dry coal storage building by front end loader	20 TPH
5	VP10-BIT-06	Maintenance of bituminous coal storage pile by front end loader and transfer to loading hopper	20 TPH
6	VP10-BIT-07	Wind erosion of bituminous coal in open coal storage area	
6	VP10-BIT-08	Wind erosion of bituminous coal in dry coal storage building	
5	VP10-REC-01	Loaded reclaim coal truck travel on unpaved roads	
5	VP10-REC-02	Empty reclaim coal truck travel on unpaved roads	

EU	Point ID	Description	Throughput
5	VP10-REC-04	Reclaim coal pile maintenance by loader, transfer to loading hopper	
6	VP10-REC-06	Wind erosion of reclaim coal pile	
NA	SV-VP-004	Wind erosion of SAC pile	
NA	Mobile Equipment	Transfer of bulk bag product to tanker via mobile belt conveyor	14 TPH

**EUG 14 Truck Unloading**

EU	Point ID	Description
NA	SV-REGN-001	Truck loading into storage silos and transfer from storage to feed silo
NA	SV-REGN-002	Truck unloading into auxiliary silo and neutralization
NA	SV-REGN-003	Truck unloading into auxiliary silo and neutralization

**EUG 15 Regeneration Kiln/Afterburner**

Emissions authorized for this EUG by Permit No. 90-006-O (M-3) follow.

Pollutant	NO <sub>x</sub>	CO	VOC	PM	SO <sub>2</sub>	HCl
Lb/hr	1.97	2.68	0.40	1.0	4.88	4.08
TPY	8.62	11.7	1.75	4.38	21.4	17.9

- a. The permittee shall be authorized to operate the regenerator kiln up to an annual production of 29,190,000 pounds per year (dry-basis) of activated carbon. [90-006-O (M-3)]
- b. All air discharges from the spent carbon receiving and product recovery operations shall be processed by a baghouse or an equivalent PM emissions control device with a design control efficiency of 99% or more. [90-006-O (M-3)]
- c. All air discharges from the rotary kiln shall be processed through: [90-006-O (M-3)]
  - 1) a baghouse or an equivalent PM emissions control device with an design control efficiency of 99% or more;
  - 2) an afterburner with a VOC design control efficiency of at least 99.99%;
  - 3) and an acid gas scrubber with a design control efficiency of at least 99% for HCl emissions control and 90% for SO<sub>2</sub> emissions control.
- d. 1) The permittee shall maintain accessible monitoring equipment to verify that the pressure drop across the process offgas baghouse is within the range of 1" to 9" WC, 12-hour rolling average.
- 2) Each one-hour rolling average of 10" or greater is a violation. [98-171-TV (M-5)]
- e. The wet scrubber shall be operated: [90-006-O (M-3)]
  - 1) using liquid with a pH of 6.0 or greater, measured at least once each calendar day;
  - 2) with liquid supplied to the wet scrubber at a rate of at least 3 GPM; and
  - 3) with nozzle pressure of at least 20 psig, calculated on a 1-hour rolling average.
- f. Afterburner requirements follow. [90-006-O (M-4)]
  - 1) The afterburner shall be operated at a temperature not less than 1,600°F, three-hour average. Design of the afterburner shall provide a residence time of at least two seconds for stack gases.

- 2) The temperature monitoring device shall be calibrated and the burner shall be inspected no less frequently than annually.
- 3) The regeneration kiln shall not be operated unless the afterburner is functioning properly.
- 4) Only pipeline quality natural gas with sulfur content less than or equal to 4 ppm shall be used as pilot fuel for the afterburner.
- 5) If the regeneration kiln handles chlorinated organic waste material, the afterburner shall be operated at a temperature not less than 1,775°F, 24-hour rolling average. Chlorinated organic waste, as used here, means any material listed in 40 CFR 261.24 that is present in the material to be regenerated in concentrations equal to or greater than the “regulatory level” shown in §261.24.
- g. The facility shall maintain records of all waste stream profiles, sufficient to demonstrate the presence of any chlorinated organic waste in each, along with records sufficient to demonstrate when each such stream was processed through the regeneration kiln and afterburner. [90-006-O (M-3)]
- h. The permittee shall conduct weekly visual observations of the opacity from the exhausts associated with these emission units using EPA Reference Method 22 and keep a record of these observations. If visible emissions are detected, then the permittee shall conduct a thirty-minute opacity reading in accordance with EPA Reference Method No. 9. [90-006-O (M-3)]
- i. Recordkeeping requirements are listed in SC#15. [OAC 252:100-8-6 (a)(3)(B)]

#### EUG 16 Regenerator Plant Material Handling

Permit No. 90-006-O (M-3) authorizes silo vent particulate emissions of 4.80 lbs/hr and 1.15 TPY. It also requires that any replacement of the existing baghouse have at least 99% capture design efficiency.

EU	Point	Description	Throughput
19	SV-REGN-003	Packaging area material handling	2
NA	SV-REGN-004	Regeneration product collector	2
NA	REGN-TRKLD	Regen bulk truck loading (drop into top of trucks at facility on northwest side of regeneration plant)	20

#### EUG 17 Regenerator Plant Bulk Handling

Permit No. 90-006-O (M-3) authorizes product handling particulate emissions of 1.46 lbs/hr and 6.57 TPY. It also requires that any replacement of the existing baghouse have at least 99% capture efficiency.

EU	Point ID	Description
27	REGN-PACLD	Regeneration plant PAC mill bulk truck loadout

#### EUG 18 Hydrochloric Acid Storage Tank

EU	Point ID	Description	Const. Date
15	SV-VP-016	Storage tank	Unknown

**EUG 19 NSPS Subpart Dc Boiler (Permit No. 98-171-C (M-1))**

In addition to NSPS Dc, this boiler is an affected source under 40 CFR 63 Subpart DDDDD, and shall comply with the tune-up provisions of that subpart.

EU	Point	Description	Const. Date
19	SV-VP-019	24.5 MMBTUH Cleaver-Brooks CBLE600	1/18/2008

**EUG 20 Cooling Tower**

The cooling tower is estimated to emit 0.02 lbs/hr of particulate. The applicable limit according to Appendix G is 74 lbs/hr. All particulates are assumed to be PM<sub>10</sub>.

EU	Point	Description
20	SV-VP-020	Cooling Tower

**EUG 21 NSPS Subpart IIII Engine**

EU	Point	Description	Const. Date
TBD	TBD	300 HP Caterpillar C9, S/N CAJSC11209	6/1/2009

2. The permittee shall be authorized to operate this facility continuously (24 hours per day, every day of the year). [OAC 252:100-8-6(a)]

3. The fuel-burning equipment, except for the 300 HP Caterpillar engine, shall use pipeline-grade natural gas. The 300 HP Caterpillar engine shall use diesel fuel that is compliant with NSPS Subpart IIII to ensure compliance with Subchapter 31. Compliance shall be shown at least once a calendar year by a current gas company bill, fuel delivery ticket, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved method. [OAC 252:100-31]

4. Each emission unit at the facility shall have a permanent identification plate attached which shows the make, model number, and serial number. [OAC 252:100-43]

5. The permittee shall keep operation and maintenance (O&M) records for all emission units that have not been modified. Such records shall at a minimum include the dates of operation, and maintenance, type of work performed, and the increase, if any, in emissions as a result. [OAC 252:100-8-6 (a)(3)(B)]

6. Performance testing for various pollutants shall be performed at certain vents to atmosphere no less frequently than every five years. Vents subject to testing include the Primary Carbonizer, the Secondary Carbonizer, and the activator furnaces. Testing shall occur downstream from all control devices. Pollutants to be tested include oxides of nitrogen (NO<sub>x</sub>), carbon monoxide (CO), oxides of sulfur (SO<sub>x</sub>), volatile organic compounds (VOC), and particulate matter (PM). PM testing shall address those aerodynamic diameters for which standards have been set, such as PM<sub>10</sub> and PM<sub>2.5</sub>. PM testing shall include both filterable (front half) and condensable (back half) emissions. Testing shall be performed in a timely manner so that results will be supplied to DEQ in subsequent applications for Title V renewal. In the event that continuous emissions monitoring (CEMs) equipment is installed on any vent, RATA testing of the CEMs shall demonstrate compliance with



this Condition. . In addition to the above testing, the permittee shall conduct performance testing for PM, with particle size analysis for PM<sub>10</sub> and PM<sub>2.5</sub>, and NO<sub>x</sub> every year with a minimum of 180 days between tests. This test will not be required in the same year in which the five year test is conducted since PM and NO<sub>x</sub> are included. [OAC 252:100-8-6 (a)(3)(A)]

7. When periodic compliance testing shows emissions in excess of the lb/hr emission limits in Specific Condition Number 1, the permittee shall comply with the provisions of OAC 252:100-9 for excess emissions. Requirements of OAC 252:100-9 include immediate notification and written notification of Air Quality and demonstrations that the excess emissions meet the criteria specified in OAC 252:100-9. [OAC 252:100-9]

8. The permittee shall conduct weekly visual observations of the opacity from eight controlled emission points in the facility using EPA Reference Method (RM) 22, and keep a record of these observations. The emission points include the afterburners and various operations with potential for particulate emissions. The points are identified as Sequence Numbers 2, 3, 6, 11, 12, 14, 15, and 16 on the 2009 annual emission inventory. The points are described in various ways, depending on the source document, so only sequence numbers are used here. If visible emissions are detected, then the permittee shall make whatever equipment adjustments are necessary and conduct a follow-up RM 22 opacity reading within 24 hours. If the second RM 22 shows visible emissions, RM 9 testing shall follow as soon as technically possible. [OAC 252:100-43]

9. The 24.5 MMBTU boiler of EUG 19 is an affected facility under 40 CFR 60, Subpart Dc, and is subject to the following requirements. [98-171-C (M-1), 40 CFR 60.60c *et seq*]

- a) Consumption of natural gas not to exceed 214,620 MMBTUs per rolling 12-month total.
- b) Records of amount of fuel combusted. (daily, monthly and 12-month rolling total).

10. The 24.5 MMBTU boiler of EUG 19 is an affected facility under 40 CFR 63, Subpart DDDDD, and is subject to the requirements of that subpart. The compliance date is projected to be March 21, 2014. [40 CFR 63.7480 *et seq*]

11. Emissions of SO<sub>2</sub> from the VAC shall be calculated based on material balance for the entire process. The sulfur content of the raw material (feed) is known or measurable, as is the sulfur content of the product. Each coal shipment shall be tested for sulfur content using ASTM D4239. The difference in total sulfur between feed and product shall be considered to have been converted to sulfur dioxide stoichiometrically and emitted. The permittee may assign portions of the total to each of the primary carbonizer, secondary carbonizer, and activator hearths, based on reasonable assumptions about sulfur lost in each. Product has been tested for sulfur content to determine both the amount of sulfur present and the ratio of sulfur in the product to sulfur in the feed. Bituminous and subbituminous coals were tested twice each during calendar years 2011 and 2012, with no test for each type of feed occurring sooner than 120 days after the preceding test. The average product sulfur retention for the four bituminous tests was 104.7% while the average product sulfur retention for the four sub bituminous tests was 96.0%. Accordingly, permittee may use the conservative retention of rate of 90% in the material balance calculations for both coal types. Because test data and emission calculations may reveal proprietary information relative to the process, only the results shall be necessary for emission inventory

purposes. However, all confidential data and supporting assumptions and calculations shall be made available to DEQ for inspections and as otherwise required. [OAC 252:100-43]

12. Emissions of particulate matter (PM) from the VAC shall be calculated as PM<sub>10</sub> or PM<sub>2.5</sub> based on material balance for the entire process. The permittee shall provide an analysis demonstrating the calculation of emissions, showing the ash content at various stages of the VAC process and explaining each calculation. ASTM D3174 shall be used to determine ash content. Because test data and emission calculations may reveal proprietary information relative to the process, only the results shall be necessary for emission inventory purposes. However, all confidential data and supporting assumptions and calculations shall be made available to DEQ for inspections and as otherwise required. [OAC 252:100-43]

13. The following records shall be maintained on site to verify Insignificant Activities. No recordkeeping is required for those operations that qualify as Trivial Activities. [OAC 252:100-8-6 (a)(3)(B)]

- a) For stationary reciprocating engines used exclusively for emergency power generation or for peaking power service, records of the size of engines, type of fuel used, and number of hours operated (annual).
- b) For fuel storage/dispensing equipment operated solely for facility owned vehicles, records of the type and amount of fuel dispensed (annual).
- c) For fluid storage tanks with a capacity of less than 39,894 gallons and a true vapor pressure less than 1.5 psia, records of the capacity of the tanks and the contents.
- d) For activities (except for trivial activities) that have the potential to emit less than 5 TPY (actual) of any criteria pollutant, the type of activity and the amount of emissions or a surrogate measure of the activity (annual).

14. The 300-hp air compressor engine is an affected facility under NSPS Subpart IIII, and shall comply with all sections including, but not necessarily restricted to, the following.

- a. §60.4200 Applicability
- b. §60.4201, 02, 03, 04, 05, & 06 Emission standards
- c. §60.4207 Fuel requirements
- d. §60.4208 What is the deadline for importing or installing stationary CI ICE produced in the previous model year?
- e. §60.4209 Monitoring requirements
- f. §60.4210 & 11 Compliance requirements
- g. §60.4212 & 13 Test methods and other procedures
- h. §60.4214 Notification, reporting, and recordkeeping requirements
- i. §60.4215 & 16 Engines used in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, and Alaska
- j. §60.4217 Emission standards for engines using special fuels
- k. §60.4218 General Provisions
- l. §60.4219 Definitions
- m. Appendices Eight tables for various purposes

15. The permittee shall maintain records of operations as listed below. These records shall be maintained on site or at a local field office for at least five years after the date of recording and shall be provided to regulatory personnel upon request. [OAC 252:100-8-6 (a)(3)(B)]

- a) Natural gas usage for each combustion unit – EUGs 2, 3, 4, 5, 6, 7 & 15 (monthly and 12-month rolling total)
- b) Analysis of feed coals – EUG 9 (each coal shipment received); also see SC #11.
- c) Thermal dryer outlet temperature – EUG 9 (at least once each 15 seconds)
- d) Process weight rates for each Carbonizer – EUGs 2 & 3 (hourly). The process weight rates for the Secondary Carbonizer may be estimated based on expected yields from the Primary Carbonizer.
- e) Hours of operation for each Carbonizer – EUGs 2 & 3 (daily).
- f) Sulfur content of the coal being processed, including sulfur weight percent and sulfur mass feed rates – EUGs 2 & 3 (each change of input and hourly sulfur feed rates – 24-hr average)
- g) Temperature of the afterburners during operation – EUGs 2, 3, 6, & 15 (at least once each 15 seconds).
- h) Activated carbon production – EUGs 6, 7 & 15 (monthly and 12-month rolling total).
- i) Baghouse pressure differentials – EUGs 7, 9, 15 (12-hour rolling), EUGs 8, 10, 12, 16 (daily).
- j) Process weight rates and hours of operation for each furnace – EUG 6 (daily). Process weights can be estimated based on the expected yields from the carbonizers.
- k) Scrubber nozzle pressures - EUG 15 (1-hour rolling average).
- l) Acid gas scrubber liquor pH and liquid flow - EUG 15 (1-hour rolling average).
- m) Operation, maintenance, and inspection log for each control device – all EUGs.
- n) Records of the date and time of Reference Method (RM) No. 22 visual emission observations, stack or emission point observed, operational status of the emission unit, observed results and conclusions, and any RM No. 9 results - the points are identified as Sequence Numbers 2, 3, 6, 8, 9, 11, 12, 14, 15, and 16 on the 2009 annual emission inventory.
- o) Amount of fuel combusted – EUG 19 (daily, monthly and 12-month rolling total).
- p) The facility shall maintain records of all waste stream profiles, sufficient to demonstrate the presence of any chlorinated organic waste in each, along with records sufficient to demonstrate when each such stream was processed through the regeneration kiln and afterburner.
- q) Records of weekly external inspections of cyclones and of O&M, per SC #1, EUG 3 and EUG 6.
- r) Boiler tune-ups required by SC # 10.
- s) Records required by NSPS Subpart IIII.
- t) Records required by SC #2, #3, #6, #7, #9, #15.
- u) The permittee shall maintain a record of GHG emissions using the methodology described in the PSD application. The permittee may use AP-42 factors for natural gas combustion and carbon material balances for coal-produced CO<sub>2</sub> emissions.
- v) Amount of coal feed to the Primary Carbonizer (12-month rolling total).

**MAJOR SOURCE AIR QUALITY PERMIT  
STANDARD CONDITIONS  
(July 21, 2009)**

**SECTION I. DUTY TO COMPLY**

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.

[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

**SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS**

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements. [OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F. [OAC 252:100-8-6(a)(3)(C)(iv)]

**SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING**

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

- (1) the date, place and time of sampling or measurement;
- (2) the date or dates analyses were performed;
- (3) the company or entity which performed the analyses;
- (4) the analytical techniques or methods used;
- (5) the results of such analyses; and
- (6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report.

[OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions.

[OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act.

[OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards (“NSPS”) under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants (“NESHAPs”) under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer’s instructions and in accordance with a protocol meeting the requirements of the “AQD Portable Analyzer Guidance” document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM<sub>10</sub>). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

#### **SECTION IV. COMPLIANCE CERTIFICATIONS**

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

## **SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM**

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification.

[OAC 252:100-8-6(c)(6)]

## **SECTION VI. PERMIT SHIELD**

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit.

[OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit.

[OAC 252:100-8-6(d)(2)]

**SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT**

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.

[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

**SECTION VIII. TERM OF PERMIT**

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

**SECTION IX. SEVERABILITY**

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

[OAC 252:100-8-6 (a)(6)]

**SECTION X. PROPERTY RIGHTS**

A. This permit does not convey any property rights of any sort, or any exclusive privilege.

[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

**SECTION XI. DUTY TO PROVIDE INFORMATION**

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking,



reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.

[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

## **SECTION XII. REOPENING, MODIFICATION & REVOCATION**

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances:

[OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

- (1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
- (2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
- (3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
- (4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d).

[OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.

[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

### **SECTION XIII. INSPECTION & ENTRY**

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

- (1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
- (2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
- (3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
- (4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

### **SECTION XIV. EMERGENCIES**

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

- (1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
- (2) the permitted facility was at the time being properly operated;
- (3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F. [OAC 252:100-8-6(a)(3)(C)(iv)]

## **SECTION XV. RISK MANAGEMENT PLAN**

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

## **SECTION XVI. INSIGNIFICANT ACTIVITIES**

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

- (1) 5 tons per year of any one criteria pollutant.
- (2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

[OAC 252:100-8-2 and OAC 252:100, Appendix I]

## **SECTION XVII. TRIVIAL ACTIVITIES**

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.

[OAC 252:100-8-2 and OAC 252:100, Appendix J]

## **SECTION XVIII. OPERATIONAL FLEXIBILITY**

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the

permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

- (1) result in no net emissions increases,
- (2) are not modifications under any provision of Title I of the federal Clean Air Act, and
- (3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

## **SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS**

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

- (1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
- (2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]
- (3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]
  - (a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
  - (b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
  - (c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
  - (d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

- (4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]
- (5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]
- (6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]
- (7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

## SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

- (1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
- (2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
- (3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

- (1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
- (2) Equipment used during the maintenance, service, repair, or disposal of appliances must

- comply with the standards for recycling and recovery equipment pursuant to § 82.158;
- (3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
  - (4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
  - (5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
  - (6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

## **SECTION XXI. TITLE V APPROVAL LANGUAGE**

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

- (1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
- (2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
- (3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).
- (4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R. § 70.8(a) and (c).
- (5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
- (6) The DEQ complies with 40 C.F.R. § 70.8(d).
- (7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
- (8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
- (9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by

DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

- (10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

## **SECTION XXII. CREDIBLE EVIDENCE**

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]



# PART 70 PERMIT

AIR QUALITY DIVISION  
STATE OF OKLAHOMA  
DEPARTMENT OF ENVIRONMENTAL QUALITY  
707 N. ROBINSON STREET, SUITE 4100  
P.O. BOX 1677  
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 98-171-C (M-2) PSD

Cabot Norit Americas USA, Inc,

having complied with the requirements of the law, is hereby authorized to construct the significant modifications at their activated carbon facility at 1432 6<sup>th</sup> Street, Mid-America Industrial Park, Pryor, Mayes County, Oklahoma,

subject to standard conditions dated July 21, 2009, and specific conditions, both attached.

This permit shall expire 18 months from the date below, except as authorized under Section VIII of the Standard Conditions.

Eddie Terrill, Director

Date



Chris Soap, Plant Manager  
Cabot Norit Americas, Inc.  
1432 6<sup>th</sup> Street, Mid-America Industrial Park  
Pryor, OK 74361-4434

SUBJECT: Permit Number: 98-171-C (M-2) PSD  
Facility: Pryor Activated Carbon Plant  
Location: Same

Dear Mr. Soap:

Enclosed is the permit retroactively authorizing construction of the Primary Carbonizer and other equipment at the referenced facility. Please note that this permit is issued subject to certain standard and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emissions Inventory Staff at 405-702-4100.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me at (918) 293-1600. Air Quality personnel are located in the Regional Office at Tulsa, 3105 E. Skelly Drive, Suite 200, Tulsa, OK, 74105.

Sincerely,

Phillip Fielder  
Air Quality Division